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Cover Photo

This skyline scene in Dallas, Texas, depicts the consumption of electricity, which provides energy to light homes and shopping centers, and to run factories.

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Electric Power Annual

1989

January 1991

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Office of Coal, Nuclear, Electric and Alternate Fuels
U.S. Department of Energy
Washington, DC 20585

This report was prepared by the Energy Information Administration, the independent statistical and analytical agency within the Department of Energy. The information contained herein should not be construed as advocating or reflecting any policy position of the Department of Energy or any other organization.

Preface

The *Electric Power Annual* presents a summary of electric utility statistics at the national, regional and State levels. The objective of the publication is to provide industry decisionmakers, government policy-makers, analysts and the general public with historical data that may be used in understanding U.S. electricity markets.

Background

The *Electric Power Annual* is prepared by the Electric Power Division; Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration (EIA); U.S. Department of Energy. The 1988 edition was redesigned and expanded to provide a wider perspective of the electric power industry. The 1989 edition continues with this perspective and has been enhanced to include financial statistics on publicly owned electric utilities.

"The Industry At A Glance" section presents a profile of the electric power industry ownership and performance; a review of key statistics for the year; and projections for various aspects of the electric power industry through 2010. Subsequent sections present data on generating capability, including proposed capability additions; net generation; fossil-fuel statistics; electricity sales, revenue and average revenue per kilowatthour sold; financial statistics; environmental statistics; and electric power transactions. In addition, the appendices provide supplemental data on major disturbances and unusual occurrences. Each section contains related text and tables and refers the reader to the appropriate publication that contains more detailed data on the subject matter.

Target Audience

In the private sector, the majority of users are researchers and analysts and ultimately the policy- and decision-making members of electric utility companies. Financial and investment institutions, economic development organizations interested in new power plant construction, special interest groups, lobbyists, electric power associations, and the news media will find the data in the *Electric Power Annual* useful.

In the public sector, the users include analysts, researchers, statisticians, and other professionals engaged in regulatory, policy, and program areas for Federal, State, and local governments. The Congress and other legislative bodies may also be interested in general trends related to electricity at State and national levels. Much of the data in this report can be used in analytic studies to evaluate new legislation. Public service commissions and other special government groups share an interest in State-level statistics. These groups can also compare the statistics for their States with those of other jurisdictions.

Coverage of Sources

Data published in the *Electric Power Annual* are compiled from two statistical forms filed monthly and seven forms filed annually by electric utilities. These forms are: the Form EIA-759, "Monthly Power Plant Report"; the Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"; the Form EIA-861, "Annual Electric Utility Report"; the Form EIA-860, "Annual Electric Generator Report"; the FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others"; the Form EIA-412, "Annual Report of Public Electric Utilities"; the Form EIA-767, "Steam-Electric Plant Operation and Design Report"; the Department of Energy, Form IE-411, "Coordinated Bulk Power Supply Program"; and the Department of Energy, Form FE-781R, "Annual Report of International Electric Import/Export Data." In addition, the *Electric Power Annual* also includes data collected on the Form IE-417R, "Electric Power System Emergency Report." A brief description of each of these forms follows. These forms are described in more detail in Appendix C, "Technical Notes."

The Form EIA-759 is used to collect monthly data on net generation; consumption of coal, petroleum, and gas; and end-of-the-month stocks of coal and petroleum for each plant by prime mover. Data are collected from all electric utilities that operate power plants (except those having plants solely on standby), approximately 800 of the 3,250 electric utilities in the United States.

The FERC Form 423 is a restricted-universe census used to collect data on power plants with a fossil-fueled steam-electric nameplate capacity of 50 or more mega-

watts (approximately 225 electric utilities). This threshold was established by the FERC. Data collected on the FERC Form 423 include information on fossil fuels regarding quantity, quality, delivered cost, origin, fuel type, supplier, and type of contract under which the fuels are purchased.

The Form EIA-861 is a census of electric utilities in the United States, its territories, and Puerto Rico. The data from the Form EIA-861 that are contained in this publication are for the United States only. The survey is used to collect information on the production, sales, revenue from sales, and trade of electricity from approximately 3,250 electric utilities.

The Form EIA-860 is used to collect data annually from all electric utilities in the United States that operate power plants or plan to operate a power plant within 10 years of the reporting year. Information on electric generators is reported by approximately 900 electric utilities.

The FERC Form 1 is an annual restricted-universe census of the major investor-owned electric utilities having, in each of the last 3 consecutive years, sales or transmission service that exceeds any one or more of the following: (1) 1 million megawatthours of total sales, (2) 100 megawatthours of sales for resale, (3) 500 megawatthours of gross interchange out, or (4) 500 megawatthours of wheeling for others (deliveries plus losses). Financial statistics including income; taxes; depreciation and amortization; electric operating revenue; electric maintenance expenses; year-end balance sheets; and, general corporate information are reported on the FERC Form 1 by approximately 180 major investor-owned electric utilities.

The Form EIA-412 is a restricted-universe census used annually to collect accounting, financial, and operating data from publicly owned electric utilities in the United States. Publicly owned electric utilities engaged in the generation, transmission, or distribution of electricity that had 120,000 megawatthours of sales to ultimate consumers and/or 120,000 megawatthours of sales for resale for the 2 previous years, as reported on the Form EIA-861, "Annual Electric Utility Report," must submit the Form EIA-412. These criteria result in approximately 450 submissions from publicly owned electric utilities.

The Form EIA-767 is a restricted-universe census of all operators of power plants with a fossil-fueled steam-electric existing or planned nameplate capacity of 10 or more megawatts. The Form EIA-767 is used to collect data annually on plant operation and equipment design (including boiler, generator, cooling system, flue gas desulfurization units, flue gas particulate collectors, and stack data). Approximately 320 electric utilities provide information regarding approximately 900 power plants on the Form EIA-767.

The Form IE-411 is an annual report supplied to the Department of Energy by the nine North American Electric Reliability Councils. These reports have been compiled from data furnished by the member electric utilities. The Form IE-411 provides the Department of Energy with information on regional plans of electric utilities for a 10-year period and is used for its peak-load information in this publication. The responsibility for collecting these data has been delegated to the Office of International Affairs and Energy Emergencies within the Department of Energy.

The Form IE-417R is used to collect information on major electric utility system emergencies, including the type of emergency, the utility and area affected, the date and time of the event, a description of the event, and expected time of restoration of service. The responsibility for collecting these data has been delegated to the Office of International Affairs and Energy Emergencies within the Department of Energy.

The Form FE-781R is used to collect data annually from holders of Export Authorizations and Presidential Permits (subject to the authority of Part II, Federal Power Act) engaged in the export of electric energy across the international borders of the United States with Canada and Mexico. The information collected on the Form FE-781R includes the volume of energy received by and/or delivered to holders of Export Authorizations and Presidential Permits, and the costs and revenue associated with these transactions. The responsibility for collecting these data has been delegated to the Office of Fuels, Fossil Energy, within the Department of Energy.

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The Industry at A Glance

Electricity is vital to virtually every aspect of the national economy. U.S. dependency on electricity is expected to expand in the future. Consequently, the role of the industry charged with the responsibility for producing electric power and maintaining electric power service in the United States is significant.

The first section of this chapter provides a graphically illustrated profile of the electric power industry. The second section of this chapter continues that descriptive profile by summarizing pertinent statistics on various aspects of the industry for the year. The third, and last section, of this chapter provides projections of pertinent statistics related to the electric power industry through 2010.

The H.B. Robinson Nuclear Power Plant is owned by the Carolina Power and Light Company. This 665-megawatt pressurized water reactor, located near Hartsville, South Carolina, was the first commercial-size nuclear plant in the Southeast.

Industry Profile

The U.S. electric power industry is a combination of electric utilities and nonutility power producers.[1] The electric utility industry is comprised of investor-owned, publicly owned, Federal, and cooperative electric utilities. Historically, investor-owned electric utilities have been most successful in serving large consolidated markets where economies-of-scale afforded the lowest prices. However, publicly owned, Federal, and cooperative electric utilities all have a role in producing, transmitting, and distributing electricity.

Investor-Owned Electric Utilities. Like all private businesses, the fundamental objective of a private (investor-owned) utility is to produce a return for investors. The investor-owned electric utility either distributes its profits to stockholders as dividends or reinvests these profits. It is granted a service monopoly in certain geographic areas and is obliged to serve all consumers. As franchised monopolies, these electric utilities are regulated and required to charge reasonable prices, to charge comparable prices to similar classifications of consumers, and to give consumers access to services under similar conditions. Most investor-owned electric utilities are operating companies that provide basic services for the generation, transmission, and distribution of electricity. The majority of investor-owned electric utilities perform all three functions. Investor-owned electric utilities operate in all States except Nebraska. The electric utilities in Nebraska consist primarily of municipal systems and public power districts. Hawaii is the only State in which all electricity generation is supplied by investor-owned electric utilities. Investor-owned electric utilities currently account for more than 75 percent of all U.S. electric utility generating capability, generation, sales, and revenue.

Publicly Owned Electric Utilities. Publicly owned electric utilities are nonprofit local government agencies established to serve their communities and nearby consumers at cost, returning excess funds to the consumer in the form of community contributions, economic and efficient facilities, and lower rates. Publicly owned electric utilities (which number approximately 2,000) include municipals, public power districts, State authorities, irrigation districts, and other State organizations. Most municipal electric utilities simply distribute power, although some larger ones produce and transmit electricity as well. They obtain their financing from municipal treasuries and from revenue bonds secured by proceeds from the sale of electricity. Public power districts and projects are concentrated in Nebraska, Washington, Oregon, Arizona, and California. Voters in a public power district elect commissioners or directors to govern the district, independent of any municipal government. State authorities, like the Power Authority of the State of New York or the South Carolina Public Service Authority, are agencies of their respective State governments. Irrigation districts may have still other forms of organization. In the Salt River Project in Arizona, for example, votes for the board of directors are apportioned according to the size of landholdings.

Federal Electric Utilities. Power produced by Federal electric utilities is not generated for profit. Most of the electricity produced is sold to publicly owned and cooperative electric utilities, and other nonprofit entities as required by law. The Federal Government is primarily a producer and wholesaler of electricity. These wholesale producers include the U.S. Army Corps of Engineers, the Bureau of Indian Affairs, the Bureau of Reclamation, and the International Water and Boundary Commission. The power marketing administrations of the U. S. Department of Energy include Bonneville, Southeastern, Southwestern, and Western Area. The Alaska Power Administration and the Tennessee Valley Authority both generate and market electricity. These power marketing administrations operate in all States except those in the Northeast, the Upper Midwest, and Hawaii.

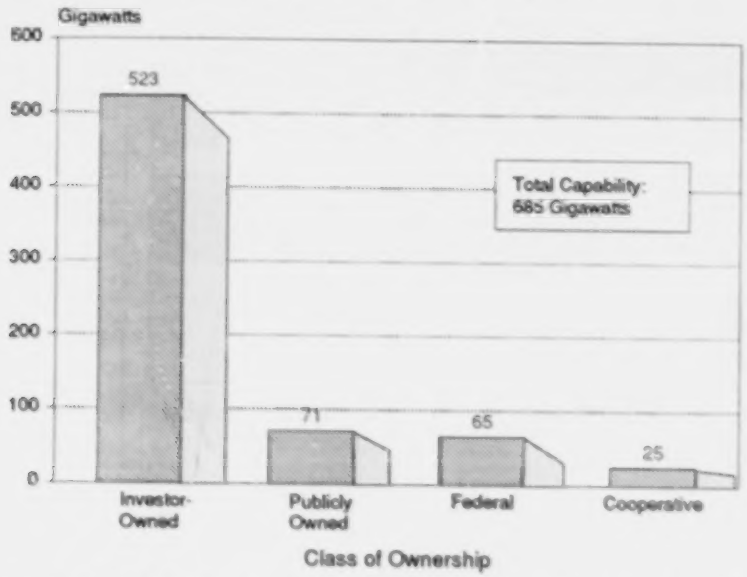
Cooperative Electric Utilities. Cooperative electric utilities are owned by their members and are established to provide electricity to those members. These electric utilities operate in rural areas with a lower concentration of consumers as these areas are not economical for investor-owned electric utilities. They are incorporated under State law and are usually directed by an elected board of directors, which in turn selects a manager. The Rural Electrification Administration, the National Rural Utilities Cooperative Finance Corporation, the Federal Financing Bank, and the Bank for Cooperatives are the most important sources of debt financing for cooperatives. There are approximately 960 cooperative electric utilities currently doing business in 46 States. Cooperative electric utilities do not operate in Connecticut, Hawaii, Massachusetts, Rhode Island, or in the District of Columbia.

Presentation of Data

The following graphic presentation on the electric utility industry by class of ownership includes: generating capability; net generation and sales of electricity; and the number of utilities, generators, and ultimate consumers. These data are collected and compiled from various sources as indicated in the Preface. Data on generating capability and net generation of electricity are presented for all electric utilities that produce power in the United States; data on electricity sales and revenue cover all electric utilities that have retail sales in the United States.

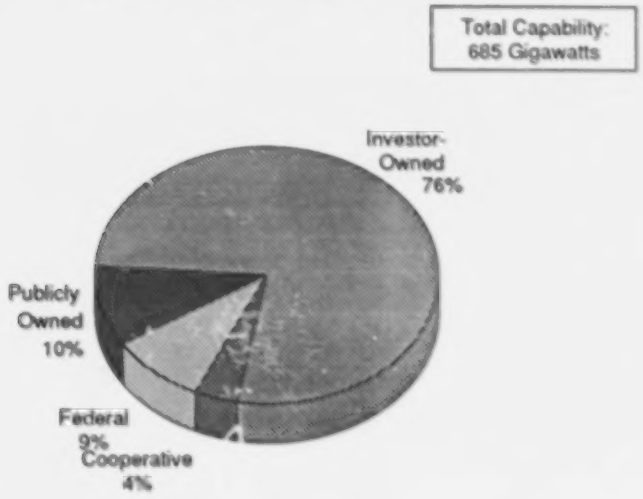
[1]In 1989, nonutility producers sold 90 billion kilowatthours of electricity to the grid.

Figure 1. Generating Capability by Class of Ownership, 1989



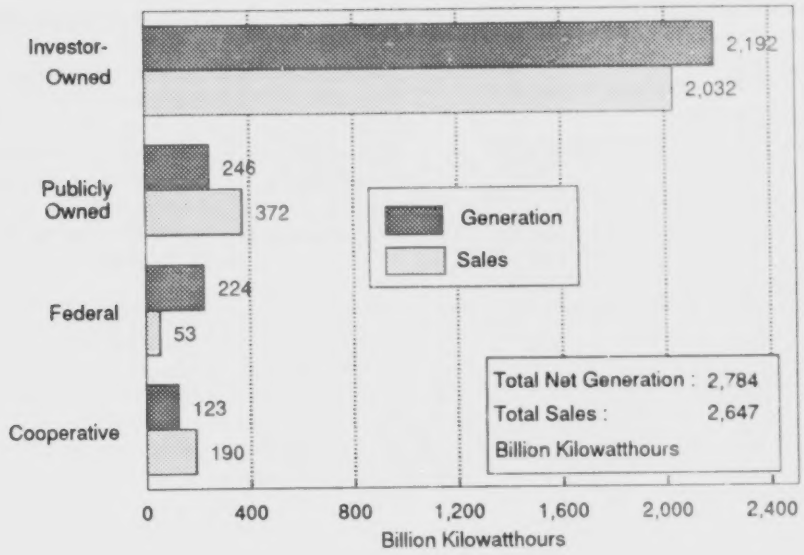
Notes: Generating capability is net summer capability. Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Figure 2. Share of Generating Capability by Class of Ownership, 1989



Notes: Generating capability is net summer capability. Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

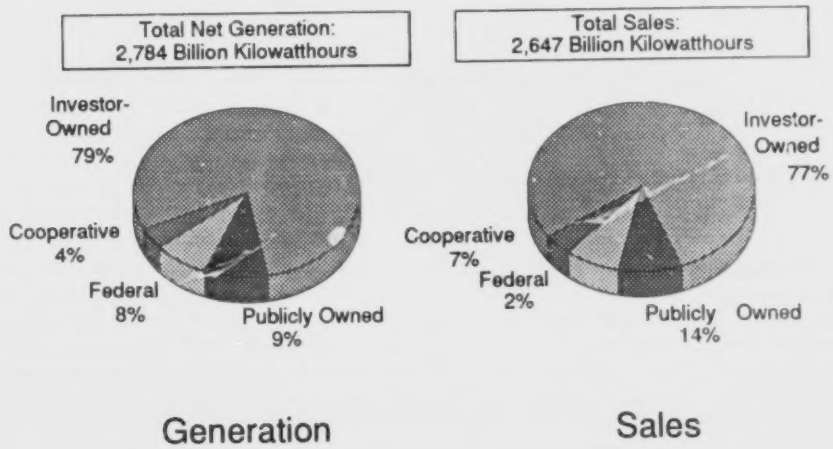
Figure 3. Net Generation and Sales to Ultimate Consumers by Class of Ownership, 1989



Notes: Total nonutility generation of electricity, which is not included in the generation data, was estimated to be 193 billion kilowatthours in 1989. Nonutility sales of electricity to electric utilities (for resale to ultimate consumers) were 90 billion kilowatthours and are included in the sales data in this graph. Totals may not equal sum of components because of independent rounding.

Sources: Energy Information Administration, **Utility generation:** Form EIA-759, "Monthly Power Plant Report"; **Nonutility generation:** *Annual Outlook for U.S. Electric Power 1990*, DOE/EIA-0474(90) (Washington, DC, June 1990); **Sales:** Form EIA-861, "Annual Electric Utility Report."

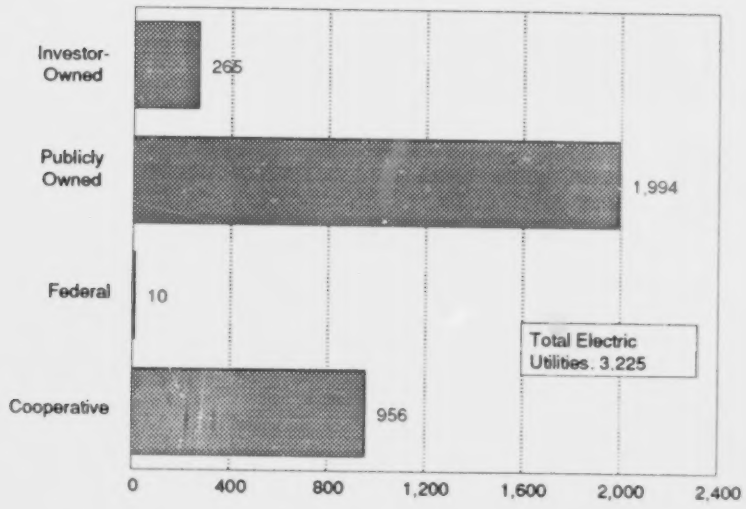
Figure 4. Share of Net Generation and Sales to Ultimate Consumers by Class of Ownership, 1989



Notes: See notes for Figure 3. Totals may not equal sum of components because of independent rounding.

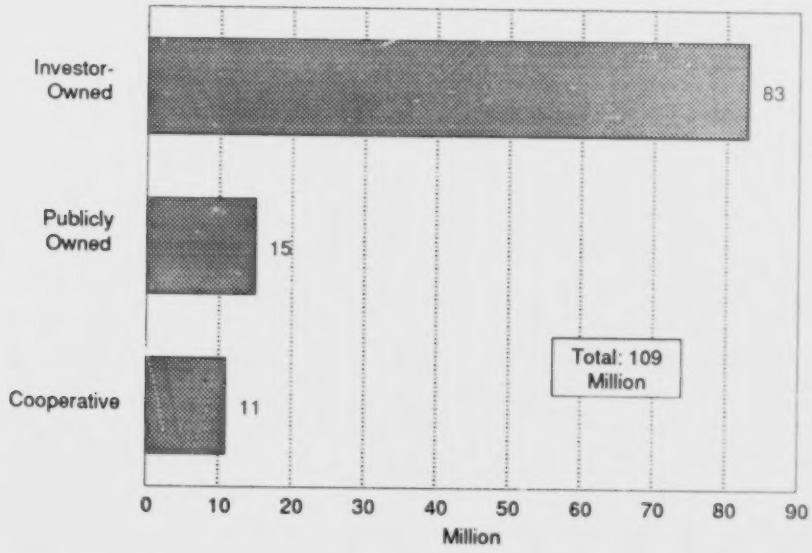
Sources: Energy Information Administration, **Utility generation:** Form EIA-759, "Monthly Power Plant Report"; **Nonutility generation:** *Annual Outlook for U.S. Electric Power 1990*, DOE/EIA-0474(90) (Washington, DC, June 1990); **Sales:** Form EIA-861, "Annual Electric Utility Report."

Figure 5. Number of Electric Utilities by Class of Ownership, 1989



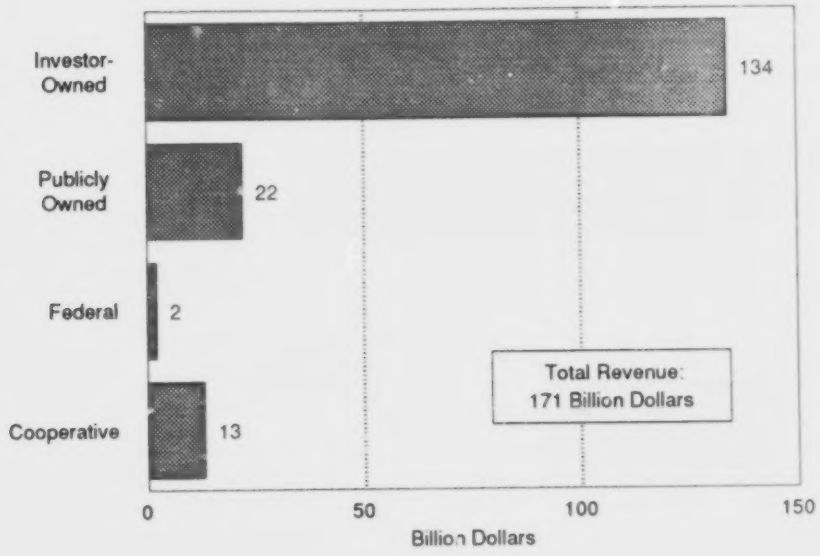
Source: Energy Information Adminstration, Form EIA-861, "Annual Electric Utility Report."

Figure 6. Number of Ultimate Consumers Served by Class of Utility Ownership, 1989



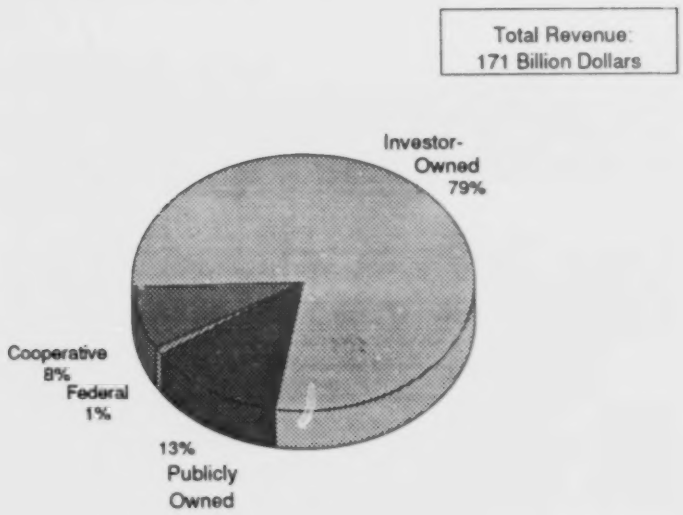
Notes: The number of ultimate consumers served by Federal electric utilities is less than 1 million. The number of ultimate consumers is an average of the number of consumers at the close of each month. Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 7. Revenue From Sales to Ultimate Consumers by Class of Ownership, 1989



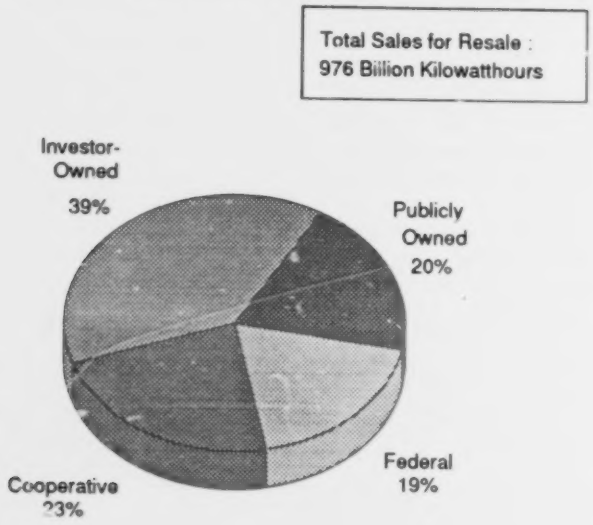
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 8. Share of Revenue From Sales to Ultimate Consumers by Class of Ownership, 1989



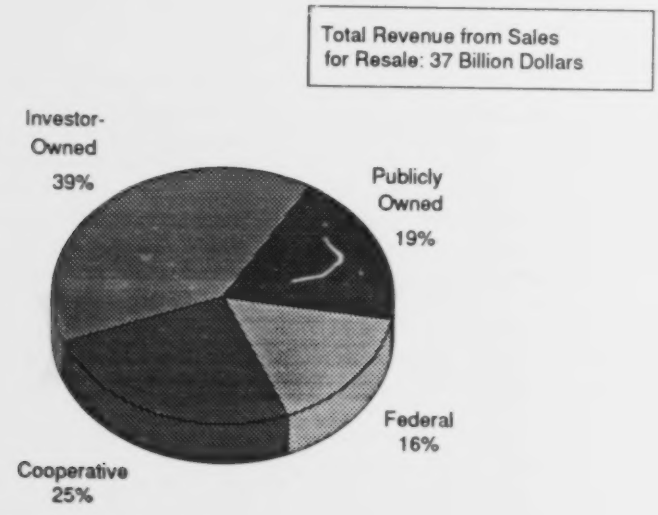
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 9. Share of Sales for Resale by Class of Ownership, 1989



Notes: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Adminstration, Form EIA-861, "Annual Elecric Utility Report."

Figure 10. Share of Revenue from Sales for Resale by Class of Ownership, 1989



Notes: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

A Review of the Year, 1989

The year 1989 was the seventh consecutive year of economic expansion in the United States; however, the rate of that expansion was substantially less than in prior years.[2] A 2.5-percent increase in real gross national product in 1989 compared with a 4.5-percent increase in 1988 was indicative of this slower growth rate. In a similar fashion, while demand for electricity in 1989 surpassed that in 1988, the rate of its growth slowed considerably. Generally mild weather (except during December) and temperate economic conditions during 1989 contributed to the slower growth during the year.

Sales Are Moderate

Total U.S. sales of electricity rose by 2.7 percent in 1989 from 1988 (Table 1). A record for total sales of electricity was set in 1989 at 2,647 billion kilowatthours. However, electricity sales in all the major electricity-consuming end-use sectors grew less in 1989 than in 1988 (Table 25). In 1989, residential sales of electricity (906 billion kilowatthours) reflected a 1-percent increase compared with the 5-percent increase reported in 1988. This was the smallest rate of growth in the residential sector in the past 5 years. Sales of electricity in the commercial sector rose 4 percent in 1989, the largest increase for all end-use sectors for the second consecutive year. Industrial sales of electricity increased by only 3 percent in 1989 compared with the 4-percent increase in 1988. The lower level of growth for sales of electricity in the industrial sector also reflects the moderation in the growth of industrial production, which increased by only 3 percent in 1989 compared with an increase of 6 percent in 1988.

The average revenue per kilowatthour of electricity sold during 1989 was 6.5 cents (Table 1). The highest average revenue per kilowatthour occurred in the residential sector at 7.6 cents (Table 26). The commercial and industrial sectors reported average revenue per kilowatthour of 7.2 and 4.7 cents, respectively, during 1989.

Generation Growth is Modest

The growth rate for total U.S. net generation reflected a similar slowdown, increasing by 3 percent in 1989 (Table 1) compared with a 5-percent increase in 1988 (Table 12). Nonetheless, a record level of generation was set when 2,784 billion kilowatthours of electricity were produced in 1989. The slower growth in the production of electricity was primarily due to milder temperatures and temperate economic conditions during 1989 in contrast to the relatively colder winter and hotter summer of the previous year.

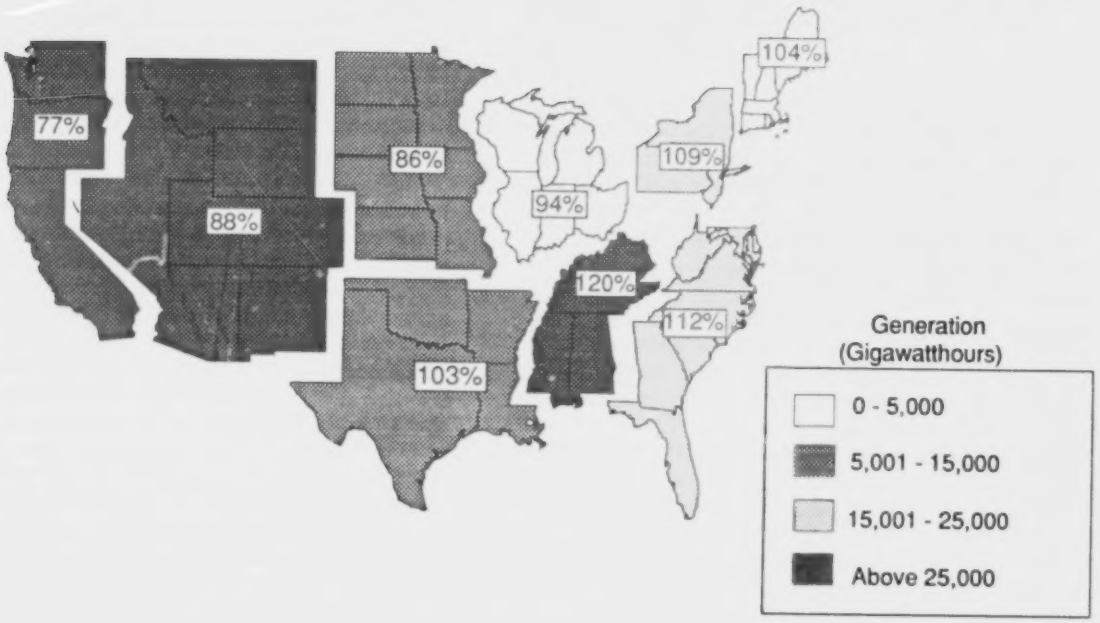
Hydroelectric Generation Begins Recovery. Generation from hydroelectric plants during 1989 was 265 billion kilowatthours, 19 percent higher than in 1988 (Table 1). Although this marks a significant recovery of hydroelectric power, generation from this energy source in 1989 remained 6 percent below the average of the prior 10 years (1979 through 1988). Even though water conditions improved overall for the United States, some areas of drought persisted through 1989 (Figure 11). Conditions remained in the severe-to-extreme drought category in central California and in the Central and North Central Regions of the country. Concurrently, the areas suffering from severe-to-moderate drought conditions in 1989 were much smaller in comparison with 1988. Most of the East, as well as the South Central States, experienced normal-to-moist conditions, representing an improvement from the scattered moderate-to-severe drought conditions during 1988. The combined-flow levels of the U.S. portions of the Mississippi, Columbia, and St. Lawrence Rivers were 33 percent higher during the water year, 1989, than the flow levels during the water year, 1988.[3]

Nuclear Generation Sets Record. During 1989, generation of electricity from nuclear power achieved a record level of 529 billion kilowatthours; however, this was an increase of less than 1 percent over the prior year (Table 1). The average performance of nuclear units in 1989 was well above that for the last 10 years. Nonetheless, the annual increase in generation was the smallest since 1980 because of the exceptionally high performance of these units in 1988.

[2]U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business*, September 1990, Vol. 70, No. 9, p. 3.

[3]United States Department of the Interior, U.S. Geological Survey, *National Water Conditions*, various issues (1989). The water year extends from October 1 to September 30. The water year is the planning cycle used and captures the seasonal nature of water supplies and the use of the water.

Figure 11. Hydroelectric Net Generation and Percent of Normal Precipitation by Census Division, 1989



Note: Alaska and Hawaii are not included.
Sources: •**Generation:** Energy Information Administration, Form EIA-759, "Monthly Power Plant Report." •**Precipitation:** National Oceanic and Atmospheric Administration, **1989:** *Monthly State, Regional and National Heating Degree Days Weighted by Population* (March 1989); **Normal:** *State, Regional and National Monthly and Annual Precipitation Weighted by Area* (August 1988).

In 1989, the average capacity factor for nuclear generating units was 62 percent; in 1988, it was 64 percent.[4] Because of scheduled and unscheduled maintenance and/or refueling at several units, nuclear power declined in the first half of 1989, but made a strong recovery in the second half. Contributing to the higher levels of nuclear-powered generation was the addition of three nuclear units during the year: Vogtle, Unit 2, operated by the Georgia Power Company; South Texas, Unit 2, operated by the Houston Lighting and Power Company; and Limerick, Unit 2, operated by the Philadelphia Electric Company. These units had a combined net summer capability rating of 3,391 megawatts.[5] During 1989, the 217-megawatt Fort St. Vrain nuclear Unit 1, owned by the Public Service Company of Colorado, was retired from service.

Coal Largest Contributor. Coal-fired generation continued to be the largest contributor to electric utility supply, providing 56 percent of total utility generation in 1989, compared to 57 percent of total utility generation in 1988. Although a record was set when 1,554 billion kilowatthours of electricity were produced from coal-fired units in 1989, this level was only 1 percent higher than the level during the previous year (Table 12). Coal-fired generation during 1988 rose by 5 percent from the level of production in 1987. The slower rate of growth in electricity demand and a substantial recovery in hydroelectric generation contributed to the slower growth in coal-fired generation. Regionally, the highest level of generation from coal occurred in the East North Central Census Division, where 356 billion kilowatthours were produced in 1989 (Table 14). The South Atlantic Census Division had the second highest level, producing 332 billion

[4]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(90/07) (Washington, DC, October 1990), p. 85.
[5]Energy Information Administration, *Inventory of Power Plants in the United States*, DOE/EIA-0095(89) (Washington, DC, September 1990), p. 3.

kilowatthours. Together, these two Census divisions produced 44 percent of the total U.S. generation from coal in 1989.

Record Coal Consumption. In parallel with the increase in coal-fired generation, consumption of coal increased by 1 percent in 1989 (Table 1). The actual amount of coal consumed by electric utilities during 1989 was 767 million short tons, an all-time high, exceeding the record set in 1988. Electric utilities also increased their receipts of coal in 1989 to 753 million short tons of coal.[6] This represented an increase of 4 percent (25 million short tons) from 1988 and established a record.

Coal Stocks Decline. The increased demand for coal can be attributed to changes in coal stocks at electric utilities over the last 2 years. Many electric utilities had prepared for a possible United Mine Workers (UMW) strike in late 1987 by increasing their stocks of coal; however, the strike was avoided. As a result, many electric utilities had excessively high coal stocks at the start of 1988. Throughout 1988, electric utilities reduced their stocks by limiting purchases of replacement coal. During 1989, electric utilities were more likely to purchase additional coal to replace coal consumed since the stock reduction was nearly complete. Consequently, receipts of coal increased at many electric utilities in 1989 compared with 1988. A very cold December also contributed to a significant drawdown in coal stockpiles. As of December 31, 1989, utilities reported coal stocks of 136 million short tons, a decrease of 7 percent from 1988 (Table 1), and the lowest end-of-year level since 1978.

Cost of Coal Down. Another factor that may have contributed to increased use of coal in 1989 was its lower cost. The average delivered cost of coal received by electric utilities in 1989 was $30.15 per short ton (Table 18), a decrease of $0.49 (2 percent) per short ton from that reported in 1988. The average delivered cost of coal purchased under contract was $30.38 per short ton, a decrease of $0.48 per short ton from the average reported in 1988 (Table 18). Coal purchased in the spot market averaged $29.07 per short ton, decreasing $0.23 from 1988 levels. Many of the same factors responsible for a decrease in the cost of coal in 1988 contributed to the decline in 1989 costs. Among these factors were buy-outs and renegotiations of high-priced coal contracts, renegotiation of rail contracts for hauling coal, increased purchases of low-cost, spot-market coal, and excess production capacity within the coal industry.

Petroleum- and Gas-Fired Generation Increase. During the first half of the year, petroleum-fired generation was 35 percent higher than it was during the corresponding period of 1988; however, petroleum-fired generation was 14 percent lower during the second half of the year than it was during the corresponding period of 1988. Whereas, gas-fired generation during the first half of 1989 was slightly above the level during the first half of 1988 and 10 percent higher during the second half compared with the corresponding period in 1988. Nevertheless, generation from both gas- and petroleum-fired units, on an annual basis, increased in 1989. Gas-fired generation increased by 6 percent in 1989 to 267 billion kilowatthours, while petroleum-fired generation increased by 6 percent to 158 billion kilowatthours (Table 1).

Petroleum Costs Up, Receipts Down. Petroleum consumption in 1989 was at its highest level since 1981. During 1989, electric utilities consumed 267 million barrels of petroleum, 8 percent above the amount reported during the previous year (Table 1). Petroleum stocks as of December 31, 1989, totaled 61 million barrels, a decrease of 12 percent from 1988. This amount was also at its lowest end-of-year level since 1972. The shift from the use of petroleum to the use of gas during 1989 is indicative of changes in fuel costs. Petroleum costs during the year increased by 19 percent while the cost of gas increased by 4 percent. Gas and petroleum are substitute fuels in dual-fired units. The average cost of petroleum delivered to electric utilities was $18.17 per barrel in 1989, an increase from $15.33 per barrel in 1988 (Table 18). World-wide petroleum prices were generally higher in 1989 than in 1988. Record cold weather in December 1989 led to soaring demand for fuel oil and contributed to the increased cost of petroleum delivered to electric utilities during the year. Electric utilities reported receiving 24 million barrels of petroleum in December 1989, at an average cost of $22.43 per barrel. Petroleum received by electric utilities in 1989 totaled 246 million barrels, an increase of 9 million barrels from 1988. The average cost of gas in 1989 was $2.42 per thousand cubic feet delivered (Table 18). During the year, the average cost of gas delivered to electric utilities varied from a low of $2.30 per thousand cubic feet in April to a high of $2.84 per thousand cubic feet in December.

The Middle Atlantic, South Atlantic, and New England Census Divisions accounted for 86 percent (212 million barrels) of all petroleum receipts (Table 23). At the State level, New York ranked highest with 66 million barrels, followed by Florida and Massachusetts (40 and 29 million barrels, respectively). Receipts of petroleum to the South Atlantic Census Division increased 9 million barrels from 1988 concurrent with a 13-percent increase in petroleum-fired generation. Receipts of petroleum to the Middle Atlantic Census Division increased by 3 million barrels in conjunction with an increase in consumption. Receipts to the New England Census Division, however, decreased by 1 million bar-

[6]Data on fossil fuels regarding quantity, quality, delivered cost, origin, fuel type, supplier, and type of contract under which the fuels are purchased are from the FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." The FERC Form 423 is a restricted-universe census for power plants with a fossil-fueled steam-electric nameplate capacity of 50 or more megawatts (approximately 225 electric utilities).

rels concurrent with lower consumption and generation levels for 1989. Receipts of petroleum to the Pacific Contiguous Census Division decreased by 4 million barrels, reflecting a drawdown in petroleum stocks.

Use of Gas Increases. Consumption of gas by electric utilities in 1989 increased 6 percent from that of 1988 (Table 1). The actual amount of gas consumed was 2,787 billion cubic feet, compared to 2,636 billion cubic feet consumed during 1988. Receipts of gas at electric utilities in 1989 totaled 2,473 billion cubic feet, an increase of 110 billion cubic feet from 1988. Several electric utilities in the New England, Middle Atlantic and South Atlantic Census Divisions reported increases in gas receipts due in part to the competitive price of gas versus petroleum. Combined, the West South Central and the Pacific Contiguous Census Divisions accounted for 1,860 billion cubic feet, 75 percent of total U.S. gas receipts (Table 23). Significant increases in gas receipts occurred in the South Atlantic, Middle Atlantic, Mountain and New England Census Divisions.

Nuclear Dominates New Capability

Nuclear capability dominated new capability additions in 1989, accounting for 49 percent of the 7 gigawatts of capability in new units (Table 4).[7] Coal-fired capability accounted for 28 percent of new unit additions. The remaining 23 percent of new additions was in gas turbine, internal combustion, hydroelectric, solar, and refuse-fueled steam units. In 1989, utilities retired less than 1 gigawatt of generating capability. As of the end of 1989, electric generating capability in the United States totaled 685 gigawatts.

Electric utilities have also proposed adding 41 gigawatts of generating capability in new units over the next 10 years (Table 10). Gas turbine, combined cycle, and coal-fired generating units account for 77 percent of these proposed capability additions.

Rate of Fossil-Fuel Emissions Slows

When fossil fuels are burned during the production of electricity, a variety of gases and particulates (including sulfur dioxide, nitrogen oxides, and carbon dioxide) are formed. If these substances are not captured by pollution control equipment, they are released into the atmosphere. Of the three major fossil fuels (coal, petroleum, and gas) used to generate electricity, coal has the highest average sulfur content. In addition, coal has historically provided the largest share (relative to other energy sources) of total U.S. generation. As a result of these two factors, generation from coal-fired power plants usually accounts for the largest share of sulfur dioxide emissions. Total fossil-fueled generation increased by 2 percent in 1989 from 1988; coal-fired generation rose by 1 percent in 1989 from 1988.

In 1989, the emissions of sulfur dioxide as a result of burning fossil fuels for the generation of electricity were estimated to be 17 million short tons, less than 1 percent higher than the level in 1988 (Table 1).[8] Nitrogen oxide emissions in 1989 (7 million short tons) rose by slightly more than 1 percent from 1988. The level of carbon dioxide emissions in 1989 were 1,997 million short tons, an increase of 28 million short tons (1 percent) from 1988. The smaller increase in emissions of sulfur dioxide, relative to the increase in generation, indicates the possibility that a larger percentage of the generation was produced using scrubbers. The U.S. average cost (including installation) for flue gas desulfurization units was $119 per kilowatt in 1989, about the same as the average installation cost in 1988 (Table 47). Average operation and maintenance costs for scrubbers declined each year from 1.61 mills per kilowatthour in 1986 to 1.34 mills per kilowatthour in 1989.[9]

The average quality of fossil fuels in 1989 was relatively constant with that in 1988 (Table 46). The heat content in 1989 for coal was 10,428 Btu per pound; for petroleum, 149,260 Btu per gallon; and for gas, 1,030 Btu per cubic foot. The 1989 average sulfur content (by weight) was 1.33 and 0.93 percent, respectively, for coal and petroleum. The average ash content for coal was 10 percent.

[7]Data on existing and planned capability are from the Form EIA-860, "Annual Electric Generator Report." The Form EIA-860 is used to collect data from all electric utilities that operate or plan to operate power plants within 10 years of the reporting date (approximately 900 electric utilities).

[8]Data regarding plant operation, equipment design, and emissions are estimates derived from the EIA-767, "Steam-Electric Plant Operation and Design Report." The Form EIA-767 is a restricted-universe census of all operators of power plants with a fossil-fueled steam-electric nameplate capacity (existing or planned) of 10 or more megawatts (approximately 320 electric utilities). See Appendix C for a detailed description of the methodology used to derive these emission estimates.

[9]A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of 1 cent).

Financial Growth Steady

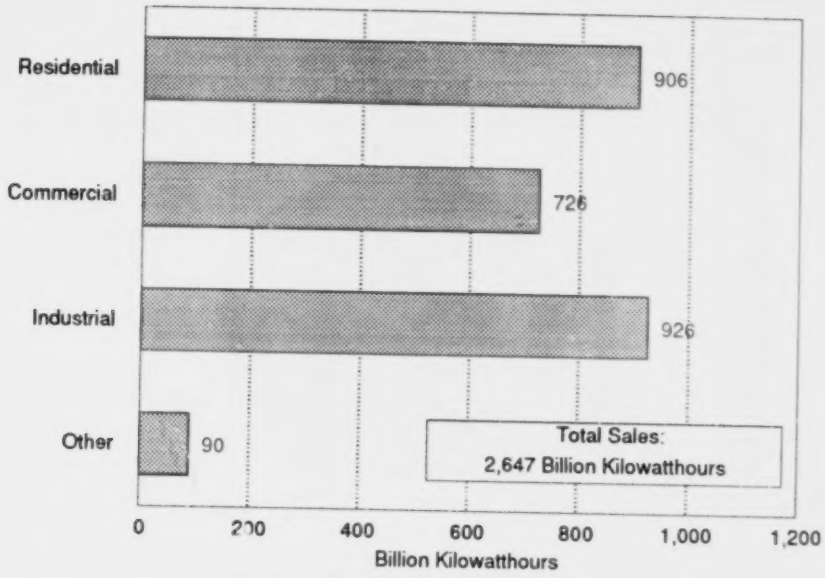
The U.S. electric utility industry in 1989 continued to experience steady growth in electric operating revenue. Financial performance was affected by aftertax write offs, accounting adjustments, and regulatory rate decisions.[10] For example, the Public Service Company of New Hampshire reported an aftertax write off of nearly $1 billion in miscellaneous income deductions and extraordinary deductions. The majority of electric utilities in 1989 improved their financial position, but aggregate industry results were reduced by a relatively small number of financially troubled electric utilities.

In 1989, total electric operating revenue at investor-owned electric utilities (which provide 77 percent of sales of electricity to ultimate consumers) increased by nearly 5 percent reaching $151 billion and net income increased by 8 percent to a total of $17 billion (Table 31). Electric operating expenses increased from $115 billion to $122 billion (5 percent). These increases in nonfuel operation and maintenance expenses, despite a nominal and real reduction in nuclear operation and maintenance expenses in 1989, impacted negatively on the earnings of the electric utility industry. Cost disallowances and extraordinary losses of nearly $4 billion impacted earnings significantly, although less than the impact experienced in 1988. Because of the continuing trend toward cost disallowances and extraordinary losses, the electric utility industry has deferred large capital investments in new large central station power plants, causing further deterioration and a slowing in future earnings. Construction work in progress declined over 16 percent in 1989, marking the sixth consecutive year of declining capital investments. However, total assets increased by 3 percent and accumulated depreciation grew by 10 percent reflecting completion of construction programs. This increase in total assets was accompanied by an associated increase in assets relating to electric utility plant, which rose by 5 percent in 1989 versus an increase in 1988 of 7 percent.

Due to the different fiscal years reported by publicly owned electric utilities, data for only those utilities whose fiscal year ended June 30, 1989, and December 31, 1989, are provided in this report. For publicly owned electric utilities with a fiscal year ending June 30, 1989, electric utility operating revenue was $10 billion; electric operating expenses were $8 billion (Table 36); and assets relating to electric utility plant were $25 billion (Table 37). For publicly owned electric utilities with a fiscal year ending December 31, 1989, electric utility operating revenue was $10 billion; electric operating expenses were $9 billion; and assets relating to electric utility plant were $35 billion. The net income of publicly owned electric utilities with a fiscal year ending December 31, 1989 ($-317 million), was impacted by the Sacramento Municipal Utility District, which reported extraordinary deductions of nearly $600 million. This deduction reflects the abandonment of the Rancho Seco Nuclear Plant and the subsequent write off at the year end.

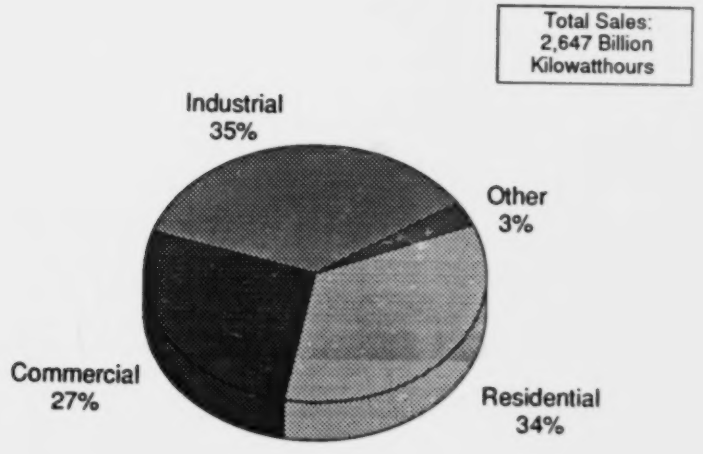
[10]Financial statistics for investor-owned electric utilities (approximately 180 electric utilities) are from the FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." Financial statistics on publicly owned electric utilities (approximately 450 electric utilities) are from the Form EIA-412, "Annual Report of Public Electric Utilities." See Appendix C for a detailed description of these restricted-universe censuses.

Figure 12. Sales to Ultimate Consumers by Sector, 1989



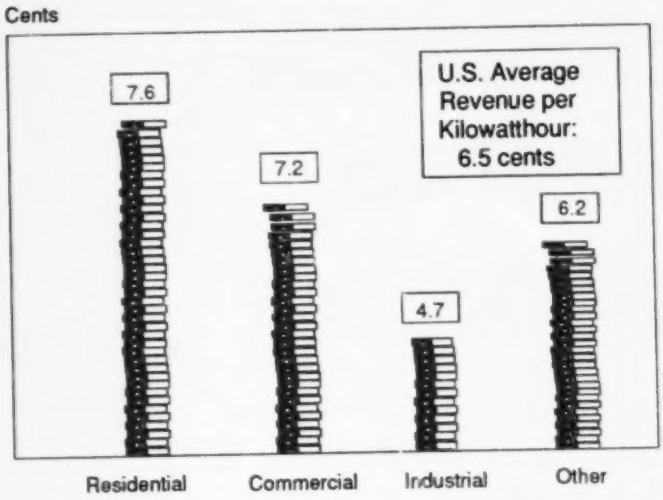
Notes: Other includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 13. Share of Sales to Ultimate Consumers by Sector, 1989



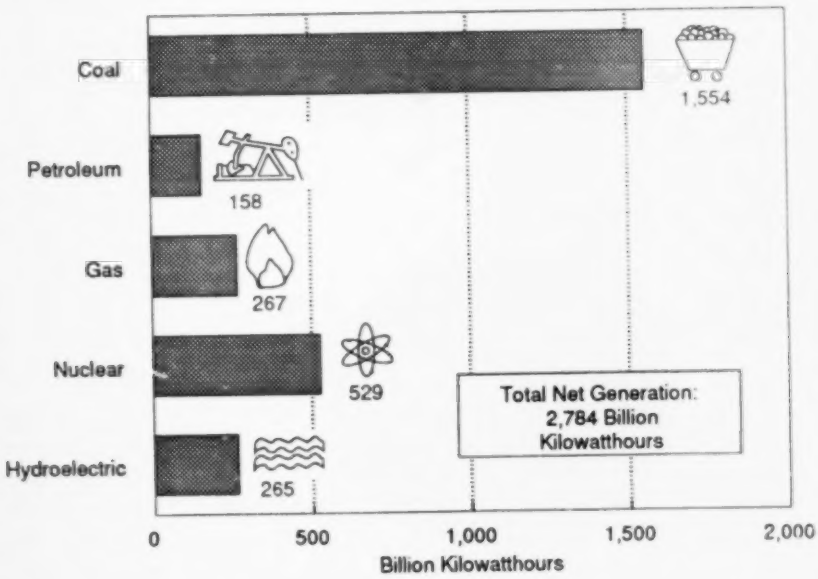
Notes: Other includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 14. Average Revenue per Kilowatthour by Sector, 1989



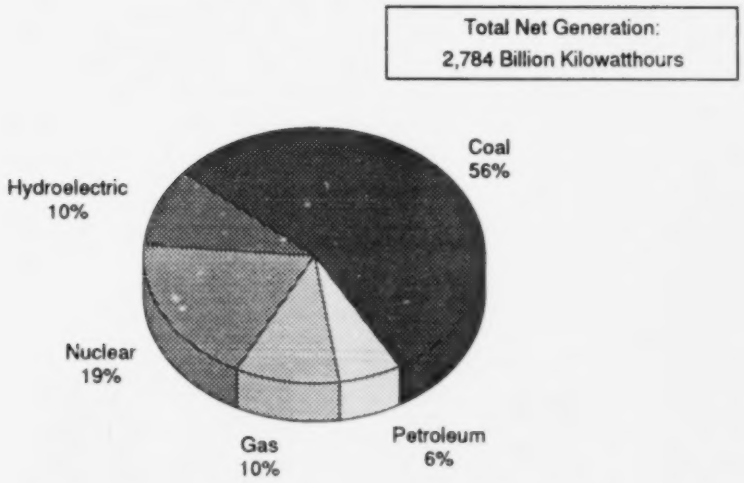
Note: Other includes sales to public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Figure 15. Net Generation by Energy Source, 1989



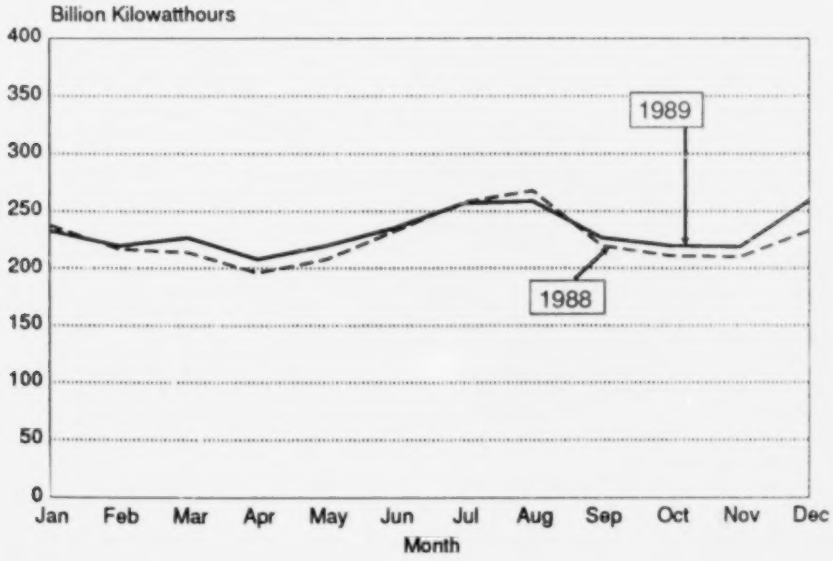
Notes: Total net generation value includes 11 billion kilowatthours of generation by other energy sources including geothermal, wood, wind, waste, and solar. Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Figure 16. Share of Net Generation by Energy Source, 1989



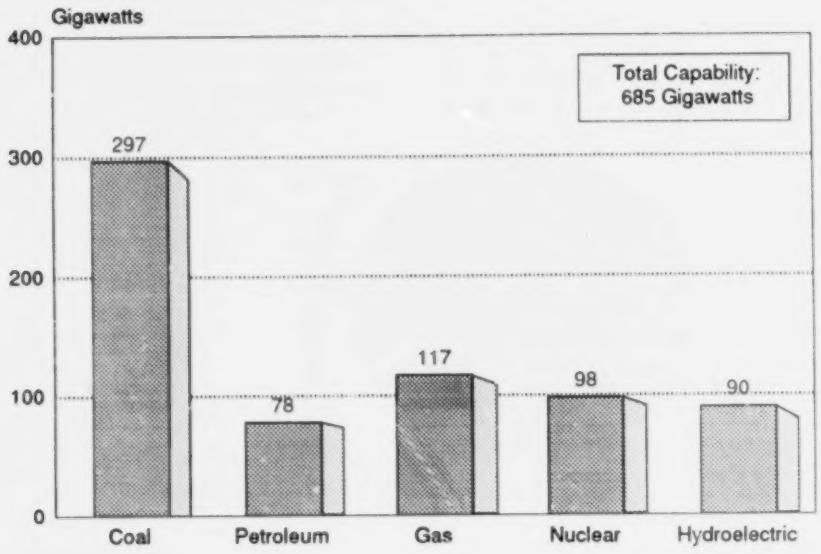
Notes: Total value includes generation from other energy sources (geothermal, wood, wind, waste, and solar), which represents less than 1 percent of total generation. Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Figure 17. Monthly Net Generation, 1989 and 1988



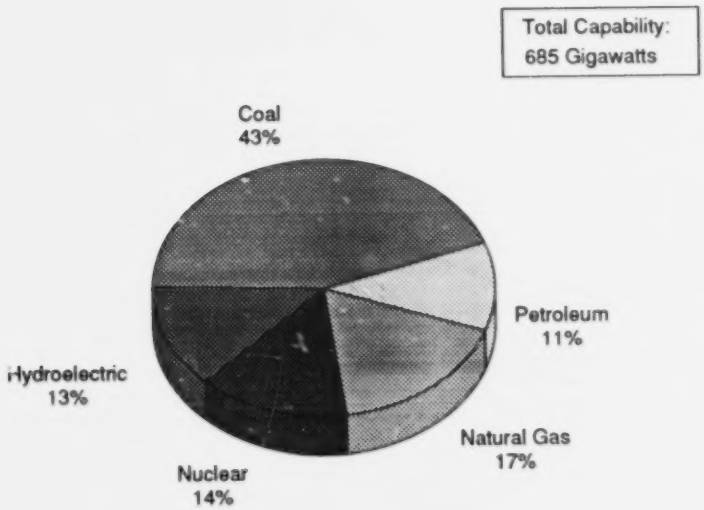
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Figure 18. Generating Capability by Energy Source, 1989



Notes: Total capability value includes 4 gigawatts of other generating capability (geothermal, refuse, waste heat, waste steam, solar, wind, and wood). Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Figure 19. Share of Generating Capability by Energy Source, 1989



Notes: Total capability value includes other generating capability (geothermal, refuse, waste heat, waste steam, solar, wind, and wood), which represents 1 percent of total capability. Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 1. Electric Power Summary Statistics for the United States, 1989 and 1988

Item	1989	1988	Percent Change from Previous Year
Generating Capability (gigawatts)[1]	**685**	**678**	**1.0**
Fossil Steam	442	440	.5
Coal	297	295	.7
Petroleum	51	51	.4
Gas	94	94	-.1
Gas Turbine/Internal Combustion	50	49	3.0
Petroleum	27	26	2.5
Gas	23	22	3.7
Hydroelectric	90	90	.2
Nuclear	98	95	3.7
Other[2]	4	4	-5.0
Generation (billion kilowatthours)	**2,784**	**2,704**	**3.0**
Coal	1,554	1,541	.8
Petroleum	158	149	6.3
Gas	267	253	5.5
Hydroelectric	265	223	18.9
Nuclear	529	527	.5
Other[3]	11	12	-5.6
Consumption			
Coal (million short tons)	767	758	1.1
Petroleum (million barrels)[4]	267	248	7.5
Gas (billion cubic feet)	2,787	2,636	5.7
Stocks			
Coal (million short tons)	136	147	-7.3
Petroleum (million barrels)[5]	61	69	-11.6
Receipts			
Coal (million short tons)	753	728	3.5
Petroleum (million barrels)[6]	246	237	4.0
Gas (billion cubic feet)[7]	2,473	2,363	4.6
Cost (Cents per million Btu)[8]			
Coal	144.6	146.6	-1.4
Petroleum[9]	289.3	243.9	18.6
Gas	235.5	226.3	4.0
Sales To Ultimate Consumers (billion kilowatthours)	**2,647**	**2,578**	**2.7**
Residential	906	893	1.4
Commercial	726	699	3.8
Industrial	926	896	3.3
Other[10]	90	90	.2
Revenue From Sales to Ultimate Consumers (billion dollars)	**171**	**164**	**4.3**
Residential	69	67	3.7
Commercial	52	49	6.1
Industrial	44	42	3.7
Other[10]	6	6	1.1
Average Revenue per Kilowatthour (cents)	**6.5**	**6.4**	**1.6**
Residential	7.6	7.5	2.2
Commercial	7.2	7.0	2.2
Industrial	4.7	4.7	.5
Other[10]	6.2	6.2	.9
Emissions (million short tons)[11]			
Sulfur Dioxide (SO2)	17	17	.3
Nitrogen Oxides (NOX)	7	7	1.3
Carbon Dioxide (CO2)	1,997	1,969	1.4

[1] Net summer capability based on primary energy source.
[2] Includes geothermal, refuse, waste heat, waste steam, solar, wind, and wood.
[3] Includes geothermal, wood, wind, waste, and solar.
[4] Does not include petroleum coke. Petroleum coke consumption in 1989 was 517 thousand short tons and in 1988 was 409 thousand short tons.
[5] Does not include petroleum coke. Petroleum coke stocks at the end of 1989 were 105 thousand short tons and in 1988 were 86 thousand short tons.
[6] Does not include petroleum coke. Petroleum coke receipts in 1989 were 495 thousand short tons and in 1988 were 356 thousand short tons.
[7] Includes small amounts of coke-oven, refinery, and blast-furnace gas.
[8] Average cost of fuel delivered to plants with a fossil-fueled steam-electric nameplate capacity of 50 or more megawatts; average cost values are weighted.
[9] Does not include petroleum coke. Petroleum coke cost in 1989 was 85.7 cents per million Btu and in 1988 was 97.2 cents per million Btu.
[10] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
[11] Includes only those power plants with a fossil-fueled steam-electric nameplate capacity (existing or planned) of 10 or more megawatts.

Notes: •Data on capability, generation, consumption, stocks, receipts and costs of fossil fuels for 1989 are final; other 1989 data are preliminary. •Totals may not equal sum of components because of independent rounding. •Percent change is calculated before rounding.

Sources: •Energy Information Administration, Form EIA-759, "Monthly Power Plant Report"; Form EIA-860, "Annual Electric Generator Report"; Form EIA-861, "Annual Electric Utility Report"; Form EIA-767, "Steam-Electric Plant Operation and Design Report." •Federal Energy Regulatory Commission FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Outlook Through 2010

Clean Air Act

On November 15, 1990, President Bush signed the Clean Air Act Amendments of 1990 into law. These projections are based, however, on legislation in effect as of June 1990, and do not include subsequent legislation.

Many decisions concerning the supply of electricity will confront the electric utility industry during the 1990's and beyond. At present, the industry is under considerable pressure to modify its traditional approach to satisfying consumer requirements. For example, regulatory commissions are encouraging utility-initiated programs to lower energy consumption and thereby limit growth in demand. This section of the *Electric Power Annual* provides projections for the demand for electricity, the price of electricity, the supply of electricity, and fuel use by electric utilities through 2010.[11]

Major Assumptions

Macroeconomic growth is a major determinant of growth in the demand for electricity, that in turn affects capacity planning, fuel use, and price. These projections are based on the assumption that from 1989 through 2010, the real gross national product (GNP) grows at an average annual rate of 2.4 percent. In addition, weather conditions are assumed to be normal. The projections presented in this section are made, assuming that existing laws and regulations remain in effect through 2010.

Electricity's Share of Demand Increases

The assumption of moderate economic growth coupled with expected normal weather results in moderate growth in the demand for electricity. Sales of electricity are expected to grow at an average rate of 2.3 percent per year through 2010 (Table 2). Electricity demand is expected to grow faster than the demand for other energy sources during the forecast period because real electricity prices remain steady while those of primary fuels increase. Of the increase in primary energy consumption from 1989 through 2010, 66 percent is accounted for by electricity. During the period, electricity will account for 44 percent of the increase in end-use energy consumption. Because of the construction of new, more electricity-intensive buildings, the commercial sector (exclusive of street lighting and transportation) is projected to show the strongest rate of growth in electricity consumption (3.2 percent per year). An expected increase in the production of equipment and machinery leads to a 2.5-percent annual growth per year in the consumption of electricity in the industrial sector. The residential sector will experience the slowest rate of growth in electricity consumption (just under 1.9 percent per year) because of a slowdown in new home construction, as well as, thermal efficiency improvements in existing structures.

Real Price Remains Stable

Real electricity prices (in 1989 cents per kilowatthour) are expected to remain relatively stable from 1989 through 2010. Prices experience a small decline before 2000 then rise slightly by 2010, reaching 7.1 cents per kilowatthour.[12]

Although real electricity prices increase slightly during the forecast period, the relative proportions of two of the price components (fuel and capital) reflect significant shifts. Capital cost reductions offset increased fuel costs during the next 10 years. Following the turn of the century, however, capital costs (per kilowatthour) level off. Therefore, increases in fuel costs result in increases in the price of electricity. The third component of electricity prices (operation and maintenance costs) remains fairly stable through 2010.

Resources Are Diverse

To meet the expected growth in demand, a variety of resources will be used. In the near term, electric utilities will utilize existing capacity more. For example, the average capacity factor for a coal-fired plant will increase from 60 percent in 1989 to 68 percent in 2010. In addition, some utilities will refurbish many of their older existing plants; 346 gigawatts of fossil-steam capacity are assumed to be life extended by 2010 with 51 gigawatts to be retired. Furthermore, electric utilities are expected to purchase 333 billion kilowatthours of electricity from nonutility producers.

[11]The discussion in this section is a summary of the base case projections provided in the Energy Information Administration, *Annual Outlook for U.S. Electric Power 1990*, DOE/EIA-0474(90)(Washington, DC, January 1990).

[12]The projected prices, in 1989 cents per kilowatthour, are from model simulations and represent average revenue per kilowatthour of demand over all consumer classes.

At the time of these forecasts, electric utilities had reported plans for building 39 gigawatts of capacity by 2010. However, since utilities are only required to submit plans for capacity expansion for the next 10 years, an additional 232 gigawatts of unplanned, unannounced, or unreported additions will be needed by 2010 to meet demand.

Net imports of electricity are expected to achieve 68 billion kilowatthours by 2010. While this represents a small share of total electricity demand, imports of electricity have important impacts regionally (particularly in the New England area, where imported power will supply up to 17 percent of demand during the forecast period.)

Gas-Fired Generation Share Increases

Gas-fired generation more than doubles by 2000, accounting for 17 percent of U.S. generation, but declines to 14 percent by 2010. Gas will surpass nuclear power to become the second-largest contributor to electric utility generation by 2000. Use of petroleum will also increase through 2000, then decline by 2010 as use of other energy sources increases. Coal will retain the majority share of U.S. generation --declining somewhat from its 56-percent share in 1989 to 52 percent in 2000 -- but then attaining 60 percent of total U.S. generation by 2010.

Uncertainty of Projections

These projections do not provide unqualified predictions for the future since a model cannot address the complexities of the real world. These projections represent expectations under a given set of assumptions; should these conditions change in any way, the projections would be affected accordingly. The uncertainty inherent in these projections should be recognized in order that the projections can be used in the proper context.

Sources

The base case projections provided in this section are summarized from the Energy Information Administration, *Annual Outlook for U.S. Electric Power 1990 (AOEP).* The AOEP contains national level projections of sources and uses of electricity through 2010 in the body of the report, as well as detailed assumptions and regional level projections in the appendices. The projections in the AOEP were made using the Intermediate Future Forecasting System and energy demands were obtained from the PC-AEO forecasting model (see AOEP, Appendix A, for a detailed discussion of these models and their assumptions). The results shown in both this report and the AOEP are consistent with those provided in the *Annual Energy Outlook 1990.*[13]

[13]Energy Information Administration, *Annual Energy Outlook 1990*, DOE/EIA-0383(90)(Washington, DC, January 1990).

Table 2. Electric Power Projections for the United States Through 2010

Selected Values	Base Case Projections			
	1995	2000	2005	2010
Electricity Sales (billion kilowatthours)	3,083	3,488	3,870	4,289
Net Imports of Electricity (billion kilowatthours)	46	60	65	68
Nonutility Purchases (billion kilowatthours)	142	206	272	333
Net Summer Capability (gigawatts)[1]				
Coal-fired Steam	300	313	363	433
Other Fossil Steam[2]	137	131	124	120
Combined Cycle	11	42	50	59
Turbine/Diesel	56	71	78	85
Nuclear Power	103	104	104	100
Pondage Hydroelectric/Other[3]	80	80	82	85
Pumped Storage Hydroelectric/Other Storage[4]	19	19	21	22
Total	706	759	822	904
Cumulative Planned Capacity Additions from December 31, 1989 (gigawatts)	24	36	38	39
Cumulative Unplanned Capacity Additions from December 31, 1989 (gigawatts)				
Coal-fired Steam	0	13	66	139
Combined Cycle	4	34	42	51
Combustion Turbine	7	18	26	34
Renewable	0	0	4	8
Total	11	66	138	232
Generation by Source (billion Kilowatthours)				
Coal	1,708	1,830	2,148	2,565
Gas	386	609	633	614
Oil	191	203	178	152
Nuclear	558	572	592	595
All Hydroelectric/Other[3]	310	312	325	339
Total	3,153	3,524	3,875	4,265
Delivered Cost of Fuel (1989 dollars per million Btu)				
Coal	1.56	1.69	1.77	1.88
Gas	2.82	3.75	4.76	5.80
Oil	3.58	4.78	5.67	6.42
Utility Fuel Consumption (trillion Btu)				
Coal	17,707	18,951	22,039	25,409
Gas	4,298	6,334	6,492	6,114
Oil	2,111	2,175	1,911	1,636
Real Electricity Price (1989 cents per kilowatthour)[5]				
Capital[6]	2.7	2.4	2.4	2.4
Fuel[7]	1.8	2.2	2.4	2.5
Operation and Maintenance[8]	2.1	2.1	2.1	2.1
Total	6.6	6.7	6.9	7.1

[1] Net Summer Capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power) as demonstrated by tests during summer peak demand.
[2] Includes oil-, gas-, and dual-fired capability.
[3] Includes geothermal power, wood waste, solar energy, and wind.
[4] Includes hydroelectric pumped storage, and, after 2000, compressed air and battery storage.
[5] The projected prices are from model simulations and represent average revenue per kilowatthour of demand over all consumer classes.
[6] Represents the cost to the utility of capital assets needed to provide reliable service (includes plant depreciation, taxes, and a sufficient return on invested capital).
[7] Includes only the direct costs of fuel inputs used to generate electricity required to meet demand.
[8] Operation and maintenance (O&M) includes all nonfuel costs necessary to operate and maintain generation, transmission, and distribution capacity used to deliver electricity to end-user sectors.

Source: Energy Information Administration, Intermediate Future Forecasting System Base Case-Run IGMD90.D0206902 ; *Annual Outlook for U.S. Electric Power 1990* DOE/EIA-0474(90)(Washington, DC, June 1990), p. 43.

On November 15, 1990, President Bush signed the Clean Air Act Ammendments of 1990 into law. These projections are based, however, on legislation in effect as of June 1990, and do not include subsequent legislation.

Generating Capability

More than one-third of the consumption of primary energy in the Nation is used to generate electricity.[14] Consumers expect electricity to be instantly available, that is, at the flick of a switch. In fact, electricity is so important to the functioning of our society that its unavailability is newsworthy. Since the Northeast blackout of 1965, the electric power industry has organized to ensure that an adequate supply of electricity is available to meet all demand requirements at any given instant, both now and in the future. In order to meet these requirements, the electric power industry has built and maintained capacity to produce electricity for various types of demand and load requirements. This chapter provides an inventory of the capability of various methods for converting energy into electricity, as well as, providing information regarding the plans the industry has for building additional capacity.

Background

Although energy cannot be created or destroyed, it can be converted from one form into another form. Electricity is the result of a conversion process that is induced by rotating a magnet within a system of coiled wires, thus converting mechanical energy into electrical energy. The machine that performs this type of energy conversion is an electric generator. The device that causes the magnet to spin is a prime mover. A generating unit includes the electrical generator and all associated or physically connected equipment (such as a prime mover) that are operated together to produce electricity.

The generating units operated by an electric utility vary by intended usage, that is, by the type of load requirements the utility must meet. The load requirements placed on an electric utility are generally categorized as *base load*, *intermediate load* and *peak load*. A baseload generating unit is normally used to satisfy all or part of the minimum load of the system and, as a consequence, produces electricity at an essentially constant rate and runs continuously. These units are generally the newest, largest, and most efficient of the three types. (The *operating efficiency* of a generating unit is a function of the amount of net heat that it can extract from the energy source for use in the production of electricity.) A peakload generating unit, which is normally the least efficient of the three types of units, is used to meet requirements during the periods of greatest load on the system. Intermediate-load generating units meet system requirements that are greater than baseload but less than peak load. These units are used during the transition between baseload and peakload requirements. Utilities also have reserve or standby generating units, which are available to the system in the event of an unexpected increase in load or an unexpected outage within the system. Consequently, an inventory of net capability must account for reserve or standby capability, as well as generating units that are not available to the system for various reasons (such as routine maintenance).

Net capability in this report, unless otherwise stated, refers to that which is *operable*. Operable capability includes both active and inactive capability. Once a new generator has been declared available to generate power to the electrical grid, it is considered a part of the operable capability of the utility until it is retired from service. Generating units that are used for standby service, generators that are placed in cold reserve or cold standby, and generators that are out of service for an extended period (exceeding one year) comprise the inactive operable capability. As of year-end 1989, about 4 percent of the operable capability was inactive.[15] The active operable capability includes the capability of generators that are generating or available to generate. However, this active operable capability does not preclude generators that may be down for scheduled maintenance, refueling, or forced outages.

An electric utility plant (station) contains generating units and auxiliary equipment that are used to convert various types of energy into electric energy. A fossil-fueled generating unit may be designed to use (burn) one or more fossil fuels to produce electricity. A generating unit capable of burning more than one fossil fuel is referred to as a dual-fired unit.[16] Some dual-fired units can only burn one fuel at a time (that is, the fuels

[14]Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(90/07) (Washington, DC, October 1990), Tables 1.4 and 2.6.
[15]Energy Information Administration, *Inventory of Power Plants in the United States*, DOE/EIA-0095(89) (Washington, DC, September 1990), p. 31.
[16]Energy Information Administration, *Fuel Choice in Steam Electric Generation: Historical Overview*, DOE/EIA-0472 (Washington, DC, August 1985).

are fired sequentially), while others can burn more than one fuel simultaneously (concurrent firing of different fuels). A sequentially fired unit generally uses one fossil fuel as its primary energy source but can switch to a second fossil fuel as an alternate energy source. Unless stated otherwise, information regarding generating capability in this report is based on the primary energy source.

Prime Movers

Electric utilities use a variety of prime movers based on the loads, availability of fuels, and energy requirements of the utility. The most common prime movers are the steam turbine, internal-combustion engine, gas combustion turbine, water turbine, and wind turbine. Most prime movers used to produce electricity today are turbines (a series of blades mounted on a shaft against which fluids are forced thus rotating the shaft connected to the generator). A turbine converts the kinetic energy of the moving fluid (liquid or gas) to mechanical energy. The fluids most commonly used in turbines are steam, hot air or combustion products, and water. The energy sources most often used with prime movers are the fossil fuels -- coal, petroleum, and natural gas.

Steam-Turbine Generating Units. Most of the electricity in the United States is produced in steam turbines. In a *fossil-fueled* steam turbine, the fuel is burned in a boiler to produce steam. The resulting steam then turns the turbine blades that turn the shaft of the generator to produce electricity. In a *nuclear-powered* steam turbine, the boiler is replaced by a reactor containing a core of nuclear fuel (primarily enriched uranium). Heat produced in the reactor by fission of the uranium is used to make steam. The steam is then passed through the turbine generator to produce electricity, as in the fossil-fueled steam turbine. Steam-turbine generating units are used primarily to serve the base load of electric utilities. Fossil-fueled steam-turbine generating units range in size (nameplate capacity) from 1 megawatt to over 1,000 megawatts. Nuclear-powered steam-turbine generating units in operation today range in size from 75 megawatts to over 1,400 megawatts.

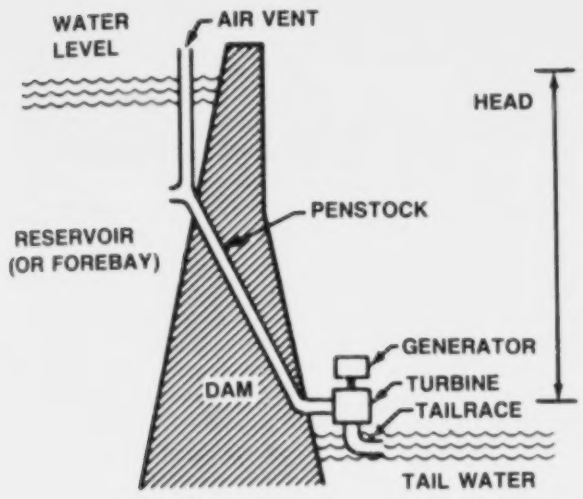
Gas Turbine Generating Units. In a gas turbine (combustion-turbine) unit, hot gases produced from the combustion of natural gas and distillate oil in a high-pressure combustion chamber are passed directly through the turbine, which spins the generator to produce electricity. Gas turbines are commonly used to serve the peak loads of the electric utility. Gas turbine units are generally less than 100 megawatts in size. Their wide choice of site locations and quick start-up time compared to steam-turbine generating units make them suitable for peaking, emergency, and reserve power.

The gas turbine, as is typical with peaking units, has a lower efficiency than the steam turbine used for baseload power. The efficiency of the gas turbine is increased when the gas turbine is coupled with a steam turbine in a *combined cycle* operation. In this system, the hot gases, which have already been used to spin one turbine generator are moved to a waste-heat recovery steam boiler where the water is heated to produce steam that in turn produces electricity by running a second steam-turbine generator. In this way, two generators produce electricity from one initial fuel input. All or part of the heat required to produce steam may come from the exhaust of the gas turbine. Thus the steam-turbine generator may be supplementarily fired in addition to the waste heat. Combined-cycle generating units generally serve intermediate loads.

Internal-Combustion Engines. These prime movers have one or more cylinders in which the combustion of fuel takes place. The engine, which is connected to the shaft of the generator, provides the mechanical energy to drive the generator to produce electricity. Internal-combustion (or diesel) generators can be easily transported, can be installed upon short notice, and can begin producing electricity nearly at the moment they start. Thus, like gas turbines they are usually operated during periods of high demand for electricity. They are generally about 5 megawatts in size.

Hydroelectric Generating Units. Hydroelectric power is the result of a process in which flowing water is used to spin a turbine connected to a generator. The two basic types of hydroelectric systems are those based on *falling water* and those based on *natural river current.* In the first system, water accumulates in reservoirs created by the use of dams. This water then falls through conduits (penstocks) and applies pressure against the turbine blades to drive the generator to produce electricity. In the second system, called a *run-of-the-river* system, the force of the river current (rather than falling water) applies pressure to the turbine blades to produce electricity. Since run-of-the-river systems do not usually have reservoirs and cannot store substantial quantities of water, power production from this type of system depends on seasonal changes and stream flow. These conventional hydroelectric generating units range in size from less than 1 megawatt to 700 megawatts. Because of their ability to start quickly and make rapid changes in power output, hydroelectric generating units are suitable for serving peak loads and providing spinning reserve power, as well as serving baseload requirements.

Figure 20. Hydroelectric Power System with Reservoir



Source: U.S. Department of Energy, *Energy Deskbook* (June 1982), p. 188.

Another kind of hydroelectric power generation is the *pumped storage* hydroelectric system. Pumped storage hydroelectric plants use the same principle for generation of power as the conventional hydroelectric operations based on falling water and river current. However, all or part of the water is made available for repeated use by pumping it from a lower to an upper reservoir. In the pumped storage operation, low-cost off-peak energy is used to pump water to an upper reservoir where it is stored as potential energy. The water is then released to flow back down through the turbine generator to produce electricity during periods of high demand for electricity.

Other Generating Units. Other methods of electric power generation, which presently contribute only small amounts to total power production, have potential for expansion. These include *geothermal, refuse, waste heat, waste steam, solar, wind,* and *wood. Geothermal* power comes from heat energy buried deep beneath the surface of the earth. Although most of this heat is at depths beyond current drilling methods, in some areas of the country magma flows close enough to the surface of the earth to produce steam. That steam can then be harnessed for use in conventional steam-turbine plants. *Solar power* is derived from the energy (both light and heat) of the sun. *Photovoltaic conversion* generates electric power directly from the light of the sun; whereas, *solar-thermal* electric generators use the heat from the sun to produce steam to drive turbines. *Wind power* is derived from the conversion of the energy contained in wind into electricity. A wind turbine is similar to a typical wind mill. However, because of the intermittent nature of sunlight and wind, high capacity utilization factors cannot be achieved for these plants. Several electric utilities have incorporated *wood* and *refuse* (for example, municipal waste, corn cobs, and oats) as energy sources for producing electricity at their power plants. These sources replace fossil fuels in the boiler. The combustion of wood and refuse creates steam that is typically used in conventional steam-electric plants.

Generator Rating

The rating of a generator is a measure of its ability to produce electricity. Generators are rated by nameplate capacity. The *nameplate capacity* is the full-load continuous rating of the generator under specified conditions, as designated by the manufacturer, and is usually indicated on a metal plate attached physically to the generator. *Net capability* is the steady hourly output that the generating unit is expected to supply to the system load as demonstrated by test procedures. The capability of the generating unit in the summer is generally less than in the winter due to high ambient-air and cooling-water temperatures, which cause generating units to be less efficient. The measure used in this publication is net summer capability. The nameplate capacity of a generator is generally greater than its net capability. Nameplate capacity is a gross rating of the output of the generator whereas net capability is the output of the generating unit based on system load deducting the requirements of the plant.

Planned Generating Unit Additions

Electric utilities must provide a continuous and dependable supply of electricity to their consumers. They must maintain a balance between supply and demand and, at the same time, maintain an adequate reserve margin to ensure system reliability. To accomplish this, electric utilities continually assess their need for new electric generating capability. Summaries of the plans of electric utilities for additions of generating capability in new units at the national, regional, and State levels from 1990 through 1999 are given in Tables 5, 10, and 11.

The most important factor in determining the need for new electric generating capability is growth in the demand for electricity. (Growth in demand is influenced primarily by economic forces, for example, the Gross National Product and the cost of fuels and electricity). Electric utilities constantly monitor their peak demands and energy requirements and usually update their forecasts of these annually. Electric utilities use various methodologies to forecast annual peak demand and energy requirements, from which they determine the amount of generating capacity that is needed to meet

expected demand. Two additional factors that contribute to the need for new generating capability are the retirements of older generators and the decreasing efficiency of aging generating units.

Before deciding to add new capability, electric utilities consider other options that may be more cost-effective in meeting future demand. Also, they may choose to combine the addition of new capability with other options that include repowering and/or life extension of their existing capability, load management programs and/or purchases of power from nonutilities.

Electric utilities are considering repowering as a cost-effective means of meeting future energy requirements. Several repowering technologies have been developed. Repowering generally consists of modifying old coal-fired electric generating units by replacing the boiler with a new combustion technology which results in better performance and an increase in capacity. Several repowering technologies were reported as part of the 10-year construction plans of utilities. In some cases, an existing steam-electric plant is reconfigured as a combined cycle plant by adding a gas turbine. Several electric utilities have already completed this kind of repowering and more of it is planned in their 10-year construction plans. Other technologies repower with clean coal technology. Repowering with clean coal technology includes replacing the furnace and boiler in an old plant with new, cleaner-burning, high-efficient coal combustion or gasification technology. Although utilities are considering their reported plans for implementing these technologies as "demonstration" projects, test programs have shown that these technologies do have dependability for future use by electric utilities in the United States.

Although life extension (plant refurbishment) adds little, if any, new generating capacity, some utilities have chosen to refurbish their plants since refurbishment can add about 20 years of life to aged plants nearing retirement and is less expensive than repowering.

Nonutilities are expected to supply a significant portion of the generating capacity needed to meet energy requirements of electric utilities over the next 10 years. By 2000, nonutility capacity is projected to total 66,000 megawatts.[17] About one-third of this capacity is expected to be sold to the electric utility grid.

With concerns about future demand, in particular, future peak demands, utilities are studying and implementing ways to get customers to reduce or shift loads. These techniques include allowing customers to have more choice in setting the cost of their energy, controlling their energy use and at the same time reducing overall demand. Reducing demand delays the need for new generating capacity. The North American Electric Reliability Council (NERC) reported expected load management programs equivalent to approximately 11,000 megawatts in 1989.[18] By 1998, NERC expects this number to be over more than 17,000 megawatts.

Once the decision has been made to add capability either by building new power plants or adding new generating units at existing power plants, the type of capability to be added is determined by matching the load to be served with the appropriate type of generating unit. If the needs of a utility are limited to capability required to meet peak demand, then gas turbine, internal-combustion, or pumped-storage hydroelectric generating units are likely to be the choice for new additions. To meet other energy requirements (intermediate and base loads), the options available to the utility include the addition of steam-electric, combined-cycle, or conventional-hydroelectric generating units.

Although utilities are responding to the various options to maintain an adequate electric power supply, the options are not without limitations. Even with the implementation of the above options, the Energy Information Administration estimates that electric utilities will build 66,000 megawatts of currently unannounced or unplanned capacity by 2000. Combined cycle and gas turbines, which require relatively short construction time, are expected to account for 52,000 megawatts of the unplanned or unannounced capacity.[19]

Data Sources

The following tables contain a summary of the number of electric generators and electric generating capability at the national, regional, and State levels for the period 1986 through 1989, as well as, capability additions planned by electric utilities for 1990 through 1999. The number of generators are reported since this is a count of the physical equipment rather than generating units, which are a combination of one or more boilers, turbines, and generators operated together to produce electricity. Data in the tables were obtained from the Form EIA-860, "Annual Electric Generator Report." Data are reported annually on the Form EIA-860 by approximately 900 electric utilities in the United States that operate power plants or plan to operate power plants within 10 years of the reporting year. These 10-year plans include generating units that are under construction or in various stages of planning at the time data are submitted. More detailed statistics from the Form EIA-860 are published in the *Inventory of Power Plants in the United States*.[20]

[17]Energy Information Administration, *Annual Outlook for U.S. Electric Power 1990*, DOE/EIA-0474(90)(Washington, DC, January 1990).
[18]North American Electric Reliability Council, *1989 Electricity Supply and Demand*, (Princeton, New Jersey, October 1989).
[19]Energy Information Administration, *Annual Outlook for U.S. Electric Power 1990*, DOE/EIA-0474(90)(Washington, DC, January 1990).
[20]Energy Information Administration, *Inventory of Power Plants in the United States*, DOE/EIA-0095(89)(Washington, DC, September 1990).

Table 3. Generating Capability by Prime Mover and Primary Energy Source, 1986-1989
(Megawatts)

Prime Mover/Primary Energy Source	1989	1988	1987	1986
Fossil Steam	**441,731**	**439,669**	**437,944**	**438,100**
Coal-Fired	296,614	294,685	292,595	290,397
Petroleum-Fired	50,967	50,782	49,869	52,299
Gas-Fired	94,150	94,202	95,479	95,404
Gas Turbine/Internal Combustion	**50,012**	**48,536**	**48,982**	**47,970**
Petroleum-Fired	27,018	26,352	26,267	25,963
Gas-Fired	22,994	22,184	22,715	22,007
Hydroelectric	**90,467**	**90,284**	**89,665**	**89,331**
Nuclear	**98,161**	**94,695**	**93,583**	**85,304**
Other[1]	**4,248**	**4,470**	**3,970**	**4,102**
U.S. Total	**684,619**	**677,654**	**674,144**	**664,807**

[1] Includes geothermal, refuse, waste heat, waste steam, solar, wind, and wood.
Notes: •Totals may not equal sum of components because of independent rounding. •Generating capability is net summer capability.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 4. Summary of Capability Additions and Retirements, and Total Operable Capability by Energy Source, 1989

Primary Energy Source	Added		Retired		Operable	
	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)
Coal	2	1,967	12	379	1,250	296,614
Petroleum	38	705	27	44	3,389	77,985
Gas	17	794	7	79	1,992	117,144
Hydroelectric	10	106	13	3	3,479	90,467
Nuclear	3	3,391	1	217	110	98,161
Other[2]	2	3	5	66	108	4,248
U.S. Total	**72**	**6,966**	**65**	**789**	**10,328**	**684,619**

[1] Net summer capability.
[2] Includes geothermal, refuse, waste heat, waste steam, solar, wind, and wood.
Notes: •Totals may not equal sum of components because of independent rounding. •Total capability cannot be calculated from the prior year's capability by adjusting for retirements and newly added capability because capability ratings for independent generators change each year and generators are purchased from or sold to nonutilities.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 5. Planned Capability Additions by Energy Source, 1990-1999

Year	Total		Petroleum & Gas		Coal	
	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)
1990	43	4,141	23	722	4	1,006
1991	38	6,238	16	668	4	2,735
1992	35	2,460	14	897	2	518
1993	34	2,443	22	1,484	1	393
1994	44	3,218	19	1,305	2	1,143
1995	39	7,294	21	1,867	5	2,780
1996	37	4,692	30	2,367	4	2,256
1997	29	3,706	21	1,993	7	1,710
1998	35	4,169	16	1,669	7	2,372
1999	34	2,871	26	1,925	3	900

Year	Nuclear		Hydroelectric		Other[2]	
	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)
1990	2	2,300	13	52	1	60
1991	2	2,320	16	515	0	0
1992	0	0	16	983	3	62
1993	0	0	9	396	2	200
1994	0	0	18	400	5	370
1995	1	1,170	9	1,036	3	441
1996	0	0	3	69	0	0
1997	0	0	1	2	0	0
1998	0	0	10	34	2	94
1999	0	0	5	46	0	0

[1] Net summer capability.
[2] Includes waste heat and solar.
Note: •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 6. Generating Capability by Census Division and State, 1989 and 1988

Census Division State	1989		1988	
	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)
New England	**669**	**22,266**	**666**	**22,117**
Connecticut	90	7,142	89	7,128
Maine	189	2,379	184	2,360
Massachusetts	193	9,945	191	9,837
New Hampshire	51	1,482	51	1,431
Rhode Island	25	262	27	259
Vermont	121	1,057	124	1,102
Middle Atlantic	**982**	**78,275**	**981**	**76,937**
New Jersey	119	13,616	117	13,510
New York	623	31,254	620	31,040
Pennsylvania	240	33,405	244	32,387
East North Central	**1,698**	**111,951**	**1,712**	**110,761**
Illinois	333	32,581	338	32,576
Indiana	152	20,648	152	19,359
Michigan	579	22,460	582	22,409
Ohio	239	25,676	241	25,703
Wisconsin	395	10,586	399	10,713
West North Central	**1,903**	**53,778**	**1,918**	**53,596**
Iowa	403	7,792	407	7,756
Kansas	440	9,568	439	9,507
Minnesota	337	8,769	347	8,760
Missouri	333	15,103	331	14,999
Nebraska	258	5,375	261	5,421
North Dakota	50	4,525	50	4,525
South Dakota	82	2,647	83	2,628
South Atlantic	**1,331**	**128,474**	**1,317**	**126,212**
Delaware	30	1,955	26	1,765
District of Columbia	4	806	4	806
Florida	370	32,680	367	32,363
Georgia	199	20,688	196	19,507
Maryland	105	9,632	104	9,607
North Carolina	206	20,180	206	20,026
South Carolina	211	14,909	209	14,819
Virginia	150	13,190	146	12,820
West Virginia	56	14,435	59	14,499
East South Central	**471**	**58,435**	**469**	**57,777**
Alabama	145	19,424	145	18,789
Kentucky	109	15,023	109	15,043
Mississippi	52	6,992	50	6,949
Tennessee	165	16,996	165	16,996
West South Central	**829**	**99,962**	**814**	**98,367**
Arkansas	102	9,625	98	9,553
Louisiana	125	16,824	127	16,850
Oklahoma	158	12,779	158	12,758
Texas	444	60,734	431	59,206
Mountain	**813**	**48,788**	**825**	**49,120**
Arizona	122	14,570	120	14,448
Colorado	170	6,639	172	7,048
Idaho	114	2,229	116	2,244
Montana	100	4,898	102	4,951
Nevada	73	4,914	74	4,857
New Mexico	55	5,111	59	5,145
Utah	126	4,738	128	4,744
Wyoming	53	5,689	54	5,682
Pacific Contiguous	**1,128**	**79,660**	**1,131**	**79,811**
California	662	44,280	660	44,429
Oregon	189	11,236	189	11,236
Washington	277	24,145	282	24,146
Pacific Noncontiguous	**504**	**3,029**	**472**	**2,957**
Alaska	426	1,546	395	1,504
Hawaii	78	1,483	77	1,453
U.S. Total	**10,328**	**684,619**	**10,305**	**677,654**

[1] Net summer capability.

Note: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 7. Coal-Fired, Nuclear, Hydroelectric, and Other Generating Capability by Census Division and State, 1989

Census Division State	Coal		Nuclear		Hydroelectric		Other[1]	
	Number of Generators	Capability[2] (megawatts)	Number of Generators	Capability[2] (megawatts)	Number of Generators	Capability[2] (megawatts)	Number of Generators	Capability[2] (megawatts)
New England	**15**	**2,755**	**8**	**5,406**	**365**	**3,105**	**5**	**229**
Connecticut	1	385	4	3,217	35	141	2	64
Maine	0	0	1	860	131	390	0	0
Massachusetts	9	1,750	2	834	64	1,853	2	118
New Hampshire	5	620	0	0	39	320	0	0
Rhode Island	0	0	0	0	1	1	0	0
Vermont	0	0	1	496	95	399	1	47
Middle Atlantic	**106**	**23,042**	**19**	**17,376**	**377**	**7,277**	**2**	**189**
New Jersey	9	1,652	4	3,863	3	330	1	120
New York	32	3,882	6	4,766	329	5,070	0	0
Pennsylvania	65	17,508	9	8,747	45	1,877	1	69
East North Central	**397**	**75,541**	**23**	**20,215**	**493**	**2,874**	**11**	**256**
Illinois	61	14,934	13	12,609	14	10	0	0
Indiana	80	19,579	0	0	20	76	0	0
Michigan	82	12,029	5	4,045	247	2,210	0	0
Ohio	120	21,866	2	2,041	7	120	4	154
Wisconsin	54	7,132	3	1,520	205	458	7	102
West North Central	**207**	**34,519**	**8**	**5,574**	**167**	**3,859**	**15**	**109**
Iowa	53	5,855	1	520	24	124	3	21
Kansas	20	5,064	1	1,135	7	2	2	*
Minnesota	55	5,716	3	1,540	54	137	10	88
Missouri	47	10,649	1	1,125	29	1,062	0	0
Nebraska	12	2,869	2	1,254	20	168	0	0
North Dakota	14	3,876	0	0	5	545	0	0
South Dakota	6	489	0	0	28	1,821	0	0
South Atlantic	**215**	**63,569**	**27**	**23,614**	**452**	**10,318**	**16**	**630**
Delaware	5	919	0	0	0	0	0	0
District of Columbia	0	0	0	0	0	0	0	0
Florida	29	9,898	5	3,825	7	46	7	482
Georgia	39	12,951	4	3,703	113	2,465	0	0
Maryland	14	3,972	2	1,650	13	428	0	0
North Carolina	47	12,470	5	4,698	105	1,979	3	80
South Carolina	24	4,818	7	6,346	121	2,183	3	69
Virginia	24	4,225	4	3,392	71	3,109	3	*
West Virginia	33	14,315	0	0	22	108	0	0
East South Central	**144**	**36,528**	**8**	**8,291**	**205**	**7,472**	**0**	**0**
Alabama	41	11,171	5	4,853	89	2,934	0	0
Kentucky	57	13,818	0	0	30	795	0	0
Mississippi	9	2,250	1	1,142	0	0	0	0
Tennessee	37	9,289	2	2,296	86	3,743	0	0
West South Central	**54**	**30,421**	**6**	**6,206**	**122**	**2,931**	**7**	**506**
Arkansas	5	3,817	2	1,694	40	1,267	0	0
Louisiana	6	3,343	2	2,011	0	0	1	203
Oklahoma	10	4,828	0	0	37	1,003	0	0
Texas	33	18,433	2	2,501	45	640	6	303
Mountain	**104**	**28,377**	**3**	**3,663**	**406**	**9,954**	**9**	**39**
Arizona	13	4,756	3	3,663	38	2,739	0	0
Colorado	31	4,942	0	0	48	1,076	0	0
Idaho	0	0	0	0	110	2,174	0	0
Montana	6	2,260	0	0	84	2,506	7	13
Nevada	8	2,692	0	0	17	1,001	0	0
New Mexico	13	3,894	0	0	6	56	1	5
Utah	14	4,424	0	0	78	141	1	21
Wyoming	19	5,410	0	0	25	261	0	0
Pacific Contiguous	**3**	**1,806**	**8**	**7,815**	**845**	**42,438**	**37**	**2,204**
California	0	0	3	5,611	414	12,490	34	1,998
Oregon	1	530	1	1,104	175	8,988	2	160
Washington	2	1,276	1	1,100	256	20,959	1	46
Pacific Noncontiguous	**5**	**56**	**0**	**0**	**47**	**239**	**6**	**85**
Alaska	5	56	0	0	43	236	5	81
Hawaii	0	0	0	0	4	3	1	4
U.S. Total	**1,250**	**296,614**	**110**	**98,161**	**3,479**	**90,467**	**108**	**4,248**

[1] Includes geothermal, refuse, waste heat, waste steam, solar, wind, and wood
[2] Net summer capability.
* Value less than 0.5.
Note: •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 8. Petroleum-, Gas-, and Dual-Fired Steam Generating Capability by Census Division and State, 1989

Census Division State	Petroleum		Gas		Dual-Fired Petroleum/Gas		Total Petroleum and Gas	
	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)
New England	**53**	**6,994**	**0**	**0**	**23**	**2,089**	**76**	**9,083**
Connecticut	22	2,418	0	0	2	528	24	2,946
Maine	14	1,053	0	0	0	0	14	1,053
Massachusetts	15	3,075	0	0	15	1,328	30	4,404
New Hampshire	2	447	0	0	0	0	2	447
Rhode Island	0	0	0	0	6	233	6	233
Vermont	0	0	0	0	0	0	0	0
Middle Atlantic	**54**	**11,368**	**0**	**0**	**51**	**9,205**	**105**	**20,573**
New Jersey	16	1,599	0	0	16	1,906	32	3,505
New York	25	6,377	0	0	35	7,299	60	13,676
Pennsylvania	13	3,392	0	0	0	0	13	3,392
East North Central	**29**	**6,026**	**9**	**228**	**16**	**734**	**54**	**6,988**
Illinois	14	3,116	2	19	9	304	25	3,439
Indiana	5	193	2	120	0	0	7	313
Michigan	6	2,474	1	9	4	401	11	2,884
Ohio	4	243	0	0	1	17	5	260
Wisconsin	0	0	4	80	2	12	6	92
West North Central	**2**	**50**	**16**	**444**	**76**	**2,303**	**94**	**2,797**
Iowa	0	0	2	44	3	60	5	104
Kansas	0	0	6	167	52	1,786	58	1,953
Minnesota	2	50	0	0	5	56	7	106
Missouri	0	0	4	101	4	79	8	180
Nebraska	0	0	4	132	11	259	15	391
North Dakota	0	0	0	0	0	0	0	0
South Dakota	0	0	0	0	1	64	1	64
South Atlantic	**55**	**8,284**	**5**	**303**	**83**	**11,470**	**143**	**20,056**
Delaware	2	54	0	0	6	684	8	738
District of Columbia	2	550	0	0	0	0	2	550
Florida	31	5,508	5	303	61	8,013	97	13,824
Georgia	2	118	0	0	8	421	10	539
Maryland	13	1,033	0	0	4	1,439	17	2,472
North Carolina	0	0	0	0	0	0	0	0
South Carolina	2	92	0	0	3	94	5	186
Virginia	3	929	0	0	1	818	4	1,747
West Virginia	0	0	0	0	0	0	0	0
East South Central	**2**	**59**	**4**	**328**	**27**	**3,210**	**33**	**3,597**
Alabama	0	0	0	0	1	50	1	50
Kentucky	2	59	1	115	0	0	3	174
Mississippi	0	0	3	213	26	3,161	29	3,374
Tennessee	0	0	0	0	0	0	0	0
West South Central	**0**	**0**	**61**	**8,148**	**266**	**47,416**	**327**	**55,564**
Arkansas	0	0	0	0	16	2,515	16	2,515
Louisiana	0	0	17	662	59	10,385	76	11,047
Oklahoma	0	0	11	677	22	5,427	33	6,104
Texas	0	0	33	6,808	169	29,089	202	35,897
Mountain	**0**	**0**	**7**	**512**	**73**	**3,272**	**80**	**3,784**
Arizona	0	0	0	0	25	1,607	25	1,607
Colorado	0	0	1	8	17	268	18	276
Idaho	0	0	0	0	0	0	0	0
Montana	0	0	0	0	1	70	1	70
Nevada	0	0	1	113	8	618	9	731
New Mexico	0	0	5	391	21	644	26	1,035
Utah	0	0	0	0	1	66	1	66
Wyoming	0	0	0	0	0	0	0	0
Pacific Contiguous	**2**	**86**	**1**	**358**	**115**	**21,079**	**118**	**21,523**
California	0	0	1	358	115	21,079	116	21,437
Oregon	0	0	0	0	0	0	0	0
Washington	2	86	0	0	0	0	2	86
Pacific Noncontiguous	**25**	**1,151**	**0**	**0**	**0**	**0**	**25**	**1,151**
Alaska	0	0	0	0	0	0	0	0
Hawaii	25	1,151	0	0	0	0	25	1,151
U.S. Total	**222**	**34,018**	**103**	**10,320**	**730**	**100,779**	**1,055**	**145,117**

[1] Net summer capability.
Note: •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 9. Petroleum-, Gas-, and Dual-Fired Gas Turbine/Internal Combustion Generating Capability by Census Division and State, 1989

Census Division State	Petroleum		Gas		Dual-Fired Petroleum/Gas		Total Petroleum and Gas	
	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)
New England	**183**	**1,307**	**0**	**0**	**17**	**381**	**200**	**1,688**
Connecticut	24	389	0	0	0	0	24	389
Maine	43	75	0	0	0	0	43	75
Massachusetts	70	625	0	0	16	361	86	986
New Hampshire	4	76	0	0	1	19	5	95
Rhode Island	18	27	0	0	0	0	18	27
Vermont	24	115	0	0	0	0	24	115
Middle Atlantic	**243**	**5,571**	**7**	**115**	**123**	**4,131**	**373**	**9,818**
New Jersey	30	1,919	3	51	37	2,176	70	4,146
New York	117	2,083	3	45	76	1,732	196	3,860
Pennsylvania	96	1,570	1	19	10	223	107	1,812
East North Central	**412**	**3,012**	**32**	**698**	**276**	**2,367**	**720**	**6,077**
Illinois	76	562	5	35	139	991	220	1,588
Indiana	26	286	8	246	11	148	45	679
Michigan	159	567	18	403	57	323	234	1,292
Ohio	63	819	1	14	37	402	101	1,235
Wisconsin	88	779	0	0	32	504	120	1,283
West North Central	**610**	**3,479**	**14**	**184**	**788**	**3,256**	**1,412**	**6,919**
Iowa	158	332	0	0	159	836	317	1,168
Kansas	52	293	5	80	295	1,040	352	1,414
Minnesota	120	822	1	1	87	359	208	1,181
Missouri	125	1,322	3	99	120	666	248	2,087
Nebraska	91	375	5	5	113	313	209	693
North Dakota	29	94	0	0	2	10	31	104
South Dakota	35	241	0	0	12	32	47	273
South Atlantic	**269**	**5,545**	**13**	**448**	**196**	**4,295**	**478**	**10,287**
Delaware	15	110	2	187	0	0	17	297
District of Columbia	2	256	0	0	0	0	2	256
Florida	123	2,737	0	0	102	1,868	225	4,605
Georgia	22	814	1	5	10	209	33	1,028
Maryland	43	711	9	246	7	153	59	1,110
North Carolina	28	478	0	0	18	476	46	953
South Carolina	8	182	1	10	42	1,117	51	1,308
Virginia	27	245	0	0	17	472	44	717
West Virginia	1	12	0	0	0	0	1	12
East South Central	**31**	**1,275**	**10**	**166**	**40**	**1,105**	**81**	**2,546**
Alabama	1	16	0	0	8	400	9	416
Kentucky	8	76	5	92	6	68	19	236
Mississippi	2	31	5	74	6	121	13	226
Tennessee	20	1,152	0	0	20	516	40	1,668
West South Central	**67**	**317**	**37**	**917**	**209**	**3,100**	**313**	**4,335**
Arkansas	17	202	0	0	22	110	39	312
Louisiana	10	44	0	0	30	176	40	220
Oklahoma	10	30	7	312	61	501	78	844
Texas	30	41	30	605	96	2,313	156	2,959
Mountain	**106**	**414**	**6**	**107**	**99**	**2,449**	**211**	**2,971**
Arizona	2	75	1	10	40	1,720	43	1,805
Colorado	41	141	0	0	32	204	73	345
Idaho	4	56	0	0	0	0	4	56
Montana	0	0	0	0	2	50	2	50
Nevada	31	78	1	12	7	401	39	490
New Mexico	6	24	2	82	1	16	9	121
Utah	13	24	2	3	17	59	32	86
Wyoming	9	18	0	0	0	0	9	18
Pacific Contiguous	**50**	**642**	**0**	**0**	**67**	**3,232**	**117**	**3,874**
California	40	548	0	0	52	2,195	92	2,743
Oregon	2	6	0	0	8	448	10	454
Washington	8	88	0	0	7	590	15	678
Pacific Noncontiguous	**394**	**789**	**7**	**281**	**20**	**428**	**421**	**1,498**
Alaska	346	464	7	281	20	428	373	1,173
Hawaii	48	325	0	0	0	0	48	325
U.S. Total	**2,365**	**22,351**	**126**	**2,917**	**1,835**	**24,745**	**4,326**	**50,012**

[1] Net summer capability.

Note: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 10. Planned Capability Additions by Energy Source and North American Electric Reliability Council Region, Alaska, and Hawaii, 1990-1999

North American Electric Reliability Council Region, Alaska, and Hawaii	Total		Petroleum & Gas		Coal	
	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)
ECAR	36	4,248	29	2,363	4	1,810
ERCOT	28	9,221	12	1,413	12	5,504
MAAC	33	3,678	29	2,752	2	790
MAIN	26	1,359	22	1,291	1	60
MAPP(U.S.)	18	1,438	15	614	2	823
NPCC(U.S.)	28	1,415	1	30	0	0
SERC	87	12,654	56	4,387	8	2,906
SPP	34	1,916	29	1,332	2	550
WSCC(U.S.)	74	5,302	14	715	8	3,370
Contiguous U.S.	**364**	**41,230**	**207**	**14,898**	**39**	**15,813**
Alaska	4	2	1	*	0	0
Hawaii	0	0	0	0	0	0
U.S. Total	**368**	**41,232**	**208**	**14,899**	**39**	**15,813**

	Nuclear		Hydroelectric		Other[2]	
	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)
ECAR	0	0	3	75	0	0
ERCOT	2	2,300	2	4	0	0
MAAC	0	0	0	0	2	136
MAIN	0	0	3	8	0	0
MAPP(U.S.)	0	0	1	*	0	0
NPCC(U.S.)	1	1,150	26	234	0	0
SERC	2	2,340	12	2,271	9	749
SPP	0	0	3	34	0	0
WSCC(U.S.)	0	0	47	875	5	342
Contiguous U.S.	**5**	**5,790**	**97**	**3,501**	**16**	**1,227**
Alaska	0	0	3	1	0	0
Hawaii	0	0	0	0	0	0
U.S. Total	**5**	**5,790**	**100**	**3,502**	**16**	**1,227**

[1] Net summer capability.
[2] Includes waste heat and solar.
* Value less than 0.5.
Note: •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 11. Planned Capability Additions by Energy Source, Census Division, and State, 1990-1999

Census Division and State	Total		Petroleum & Gas		Coal	
	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)	Number of Generators	Capability[1] (megawatts)
New England	**12**	**1,260**	**1**	**30**	**0**	**0**
Connecticut	0	0	0	0	0	0
Maine	7	73	0	0	0	0
Massachusetts	1	30	1	30	0	0
New Hampshire	1	1,150	0	0	0	0
Rhode Island	0	0	0	0	0	0
Vermont	3	7	0	0	0	0
Middle Atlantic	**28**	**1,452**	**11**	**1,284**	**0**	**0**
New Jersey	12	1,298	11	1,284	0	0
New York	16	154	0	0	0	0
Pennsylvania	0	0	0	0	0	0
East North Central	**49**	**4,174**	**42**	**2,776**	**4**	**1,390**
Illinois	2	71	2	71	0	0
Indiana	10	914	10	914	0	0
Michigan	0	0	0	0	0	0
Ohio	16	2,085	13	755	3	1,330
Wisconsin	21	1,103	17	1,035	1	60
West North Central	**47**	**3,176**	**42**	**1,803**	**4**	**1,373**
Iowa	10	241	9	241	0	0
Kansas	7	18	7	18	0	0
Minnesota	3	563	2	163	1	400
Missouri	21	1,687	19	1,137	2	550
Nebraska	2	173	2	173	0	0
North Dakota	1	423	0	0	1	423
South Dakota	3	70	3	70	0	0
South Atlantic	**94**	**11,253**	**66**	**5,275**	**8**	**2,904**
Delaware	2	204	1	83	0	0
District of Columbia	0	0	0	0	0	0
Florida	43	3,955	36	2,937	2	458
Georgia	7	1,176	0	0	0	0
Maryland	19	2,176	17	1,386	2	790
North Carolina	0	0	0	0	0	0
South Carolina	11	2,300	4	335	2	870
Virginia	12	1,442	8	536	2	786
West Virginia	0	0	0	0	0	0
East South Central	**24**	**5,026**	**14**	**1,273**	**3**	**1,272**
Alabama	8	1,239	6	447	2	792
Kentucky	10	1,248	6	693	1	480
Mississippi	4	202	2	133	0	0
Tennessee	2	2,340	0	0	0	0
West South Central	**39**	**9,732**	**20**	**1,891**	**12**	**5,504**
Arkansas	4	116	1	83	0	0
Louisiana	0	0	0	0	0	0
Oklahoma	4	263	4	263	0	0
Texas	31	9,353	15	1,545	12	5,504
Mountain	**42**	**4,506**	**11**	**566**	**8**	**3,370**
Arizona	10	1,139	4	247	2	720
Colorado	2	153	1	62	0	0
Idaho	7	143	0	0	0	0
Montana	0	0	0	0	0	0
Nevada	11	2,655	4	256	5	2,250
New Mexico	0	0	0	0	0	0
Utah	12	415	2	2	1	400
Wyoming	0	0	0	0	0	0
Pacific Contiguous	**29**	**647**	**0**	**0**	**0**	**0**
California	23	597	0	0	0	0
Oregon	0	0	0	0	0	0
Washington	6	50	0	0	0	0
Pacific Noncontiguous	**4**	**2**	**1**	*	**0**	**0**
Alaska	4	2	1	*	0	0
Hawaii	0	0	0	0	0	0
U.S. Total	**368**	**41,232**	**208**	**14,899**	**39**	**15,313**

[1] Net summer capability.

* Value less than 0.5.

Note: •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 11. Planned Capability Additions by Energy Source, Census Division, and State, 1990-1999 (Continued)

Census Division and State	Nuclear		Hydroelectric		Other[1]	
	Number of Generators	Capability[2] (megawatts)	Number of Generators	Capability[2] (megawatts)	Number of Generators	Capability[2] (megawatts)
New England	1	1,150	10	80	0	0
Connecticut	0	0	0	0	0	0
Maine	0	0	7	73	0	0
Massachusetts	0	0	0	0	0	0
New Hampshire	1	1,150	0	0	0	0
Rhode Island	0	0	0	0	0	0
Vermont	0	0	3	7	0	0
Middle Atlantic	0	0	16	154	1	14
New Jersey	0	0	0	0	1	14
New York	0	0	16	154	0	0
Pennsylvania	0	0	0	0	0	0
East North Central	0	0	3	8	0	0
Illinois	0	0	0	0	0	0
Indiana	0	0	0	0	0	0
Michigan	0	0	0	0	0	0
Ohio	0	0	0	0	0	0
Wisconsin	0	0	3	8	0	0
West North Central	0	0	1	*	0	0
Iowa	0	0	1	*	0	0
Kansas	0	0	0	0	0	0
Minnesota	0	0	0	0	0	0
Missouri	0	0	0	0	0	0
Nebraska	0	0	0	0	0	0
North Dakota	0	0	0	0	0	0
South Dakota	0	0	0	0	0	0
South Atlantic	0	0	12	2,271	8	802
Delaware	0	0	0	0	1	122
District of Columbia	0	0	0	0	0	0
Florida	0	0	0	0	5	560
Georgia	0	0	7	1,176	0	0
Maryland	0	0	0	0	0	0
North Carolina	0	0	0	0	0	0
South Carolina	0	0	5	1,095	0	0
Virginia	0	0	0	0	2	120
West Virginia	0	0	0	0	0	0
East South Central	2	2,340	3	75	2	69
Alabama	0	0	0	0	0	0
Kentucky	0	0	3	75	0	0
Mississippi	0	0	0	0	2	69
Tennessee	2	2,340	0	0	0	0
West South Central	2	2,300	5	37	0	0
Arkansas	0	0	3	34	0	0
Louisiana	0	0	0	0	0	0
Oklahoma	0	0	0	0	0	0
Texas	2	2,300	2	4	0	0
Mountain	0	0	21	421	2	149
Arizona	0	0	4	172	0	0
Colorado	0	0	1	92	0	0
Idaho	0	0	7	143	0	0
Montana	0	0	0	0	0	0
Nevada	0	0	0	0	2	149
New Mexico	0	0	0	0	0	0
Utah	0	0	9	13	0	0
Wyoming	0	0	0	0	0	0
Pacific Contiguous	0	0	26	454	3	193
California	0	0	20	404	3	193
Oregon	0	0	0	0	0	0
Washington	0	0	6	50	0	0
Pacific Noncontiguous	0	0	3	1	0	0
Alaska	0	0	3	1	0	0
Hawaii	0	0	0	0	0	0
U.S. Total	5	5,790	100	3,502	16	1,227

[1] Includes waste heat and solar.
[2] Net summer capability.
* Value less than 0.5.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Net Generation

This chapter provides summary statistics on the amount of electricity produced in the United States. The different energy sources used to produce electric power are also discussed in this chapter.

Background

The production of electricity is generally referred to as generation, and is measured in kilowatthours. Gross generation is the amount of power produced by an electric power plant (station), measured at the terminals of the plant (that is, prior to the point at which the power leaves the station and is available to the system). Some of the electric power generated at a power plant is used to operate equipment at the plant. Power used at the plant generally ranges between 1 percent (for hydroelectric units) and 7 percent (for steam-electric units). Net generation is the power available to the system (gross generation less use at the plant); however, it is greater than that available to consumers due to losses during transmission and distribution. Net generation is the measure of electric power production used in this report.

The energy sources used for producing electricity fall into two broad categories: nonrenewable (those that cannot be replaced once used) and renewable (those that are constantly replenished). The most common nonrenewable energy sources used for generation are the fossil fuels (coal, petroleum, and gas) and uranium. These energy sources account for about 90 percent of U.S. net generation. The renewable energy sources include the water in rivers, streams, or lakes (hydroelectric); the light or heat of the sun (solar); wind; heat from beneath the surface of the earth (geothermal); and organic wastes, which are produced by either natural or technological processes.

The choice of generating technology and fuel used to produce electricity is of major importance to electric utilities because the goal is to provide the least-cost and most reliable electricity possible to consumers. A variety of factors influence the selection of technology and fuel including the capital costs of the technology, operations and maintenance costs, environmental restrictions on the technology and use of the fuel, regulations affecting fuel use, the cost and availability of the fuel, and the availability of capacity associated with the type of fuel. The previous chapter covers the type and amount of U.S. generating capability currently existing, as well as, proposed capability additions planned for the period 1990 through 1999. The succeeding chapter covers the costs of fossil fuels.

Generation from Fossil Fuels

Coal. Historically, most of the generation in the United States has been from coal. After the Arab oil embargo of 1973, concerns over the availability of petroleum imports, increasing petroleum costs, and curtailments of natural gas made coal-fired generation even more important. In 1978, the passage of the Powerplant and Industrial Fuel Use and Natural Gas Policy Acts encouraged further use of coal by electric utilities. Although both Federal and State environmental laws and regulations exist, during the 1970's, renewed interest in environmental issues raised concerns about electric power plant emissions, particularly from those burning coal. The Clean Air Act Amendments of 1990, a bill whose goal is a 10-million-ton reduction in sulfur dioxide emissions and a 2-million-ton reduction in nitrogen oxide emissions from 1980 levels, was signed into law by President Bush on November 15, 1990 (see the chapter on Environmental Statistics). Coal-fired generation continues to provide more than one-half the total net generation of electricity in the Nation. Most of the electricity production from coal occurs in the East North Central and South Atlantic Census Divisions where substantial amounts of coal are mined.

Petroleum. During the early 1970's, electric utilities used petroleum extensively to generate electricity because it was a relatively inexpensive fuel. However, after the 1973 embargo by the Organization of Petroleum Exporting Countries (OPEC) on petroleum exports to the United States, petroleum prices rose sharply. Further price increases occurred in 1979 and 1980 following the Iranian revolution and subsequent reductions in Iranian petroleum exports. Consequently during the past decade, utilities have not built large, petroleum-fired steam units. In addition, many utilities have either converted steam units to coal or switched fuels where dual-fired capability exists. Most of the utilities that still rely heavily on petroleum to generate electricity are located along the eastern seaboard and in California.

Gas. The demand for gas to heat homes and serve business and industry has historically taken priority

over the demand of electric utilities under both Federal and State regulations. In the 1970's, many utilities were on occasion denied gas when available pipelines reached capacity in serving heating demand during the months from November to March (the peak heating season). By the middle 1970's, curtailments to electric utilities also occasionally occurred during the nonheating season as producers conserved supply in preparation for heating season demand. In the face of an attractive interstate price structure but deprived of supplies during many months of the year, utilities in the 1970's used relatively less-expensive gas when it was available, then switched to other more expensive fuels when gas supplies were curtailed. Gas became more available to utilities with the passage of the Natural Gas Policy Act of 1978 and more frequent exemptions from the gas-use restrictions of the Powerplant and Industrial Fuel Use Act (Fuel Use Act) of 1978. Amendments to the Fuel Use Act in 1987 have created potential for additional use of gas. These amendments eased restrictions on the use of gas by removing a legal requirement to obtain an exemption for the construction of new gas-fired generating capability. The West South Central Census Division, where most of the gas production in the Nation occurs, supplies more than half of the gas-fired generation in the country.

Generation from Uranium

Generation from nuclear power has generally increased since the 1950's, and this trend continues. Since 1984, nuclear plants have provided the second largest share of total U.S. generation of electricity, after coal-fired plants. Although no new nuclear units have been ordered since 1978, and the units ordered after 1974 were not built, many that were under construction have either been completed and entered service or will enter service in the near future. Licensing delays, questions about radioactive waste disposal, and concern about nuclear plant safety have slowed these units from entering service and are still major obstacles to additional growth in the use of this energy source for generating electricity. Most of the nuclear-powered generation comes from the Middle Atlantic, East North Central, and South Atlantic Census Divisions (where over 60 percent of the nuclear units in the country are located.)

Generation from Renewable Fuels

Hydroelectric. Water is currently the leading renewable energy source used to generate electric power. Hydroelectric plants operate where suitable waterways are available; many of the best of these sites have already been developed. Generating electricity using water has several advantages. The major advantage is that water is a resource, which is renewable. A pumped-storage hydroelectric plant offers a second advantage in that these systems use electricity produced by other generators (generally those that serve baseload requirements) to pump water from one storage area (reservoir) to another. Later this water is allowed to flow from the higher reservoir to the lower one through the generator. In this manner, the same energy source (water) is used twice. Net hydroelectric generation statistics reflected in this report are derived by deducting the generation used for pumping (in house use) from the total (gross) hydroelectric generation. Since water is renewable, it is a source of cheap power. In addition, because there is no fuel combustion, there is little air pollution in comparison with fossil fuel plants and limited thermal pollution in comparison with nuclear plants. Like other energy sources, the use of water for generation has limitations, including environmental impacts caused by damming rivers and streams, which affects the habitats of the local plant, fish, and animal life. Over 60 percent of the hydroelectric power in the United States is generated in the Pacific and Rocky Mountain States.

Other Sources. Other renewable resources -- geothermal (heat energy deep beneath the surface of the earth), wood, waste, wind, and the sun (solar) -- are energy sources that are constantly replenished. These energy sources have received increased attention in recent years, but a limited number of such generating facilities are in use today. The major obstacles to their use are technology and cost. Currently, renewable resources (other than water) supply less than 1 percent of the electricity for the Nation. Most of the electricity produced from this category is from geothermal power. Electric utilities currently operate geothermal plants in three States (California, Hawaii, and Utah). The Geysers, operated by the Pacific Gas and Electric Company, is the largest geothermal plant in the Nation. Only a few utilities operate units that produce electricity from wind and solar energy. The largest share of the electricity from these energy sources is produced from facilities in California. Wood and waste resources can be used to replace fossil fuels in utility boilers. To date, just a few electric generating units have been built that use wood or waste products as a primary fuel.

Data Sources

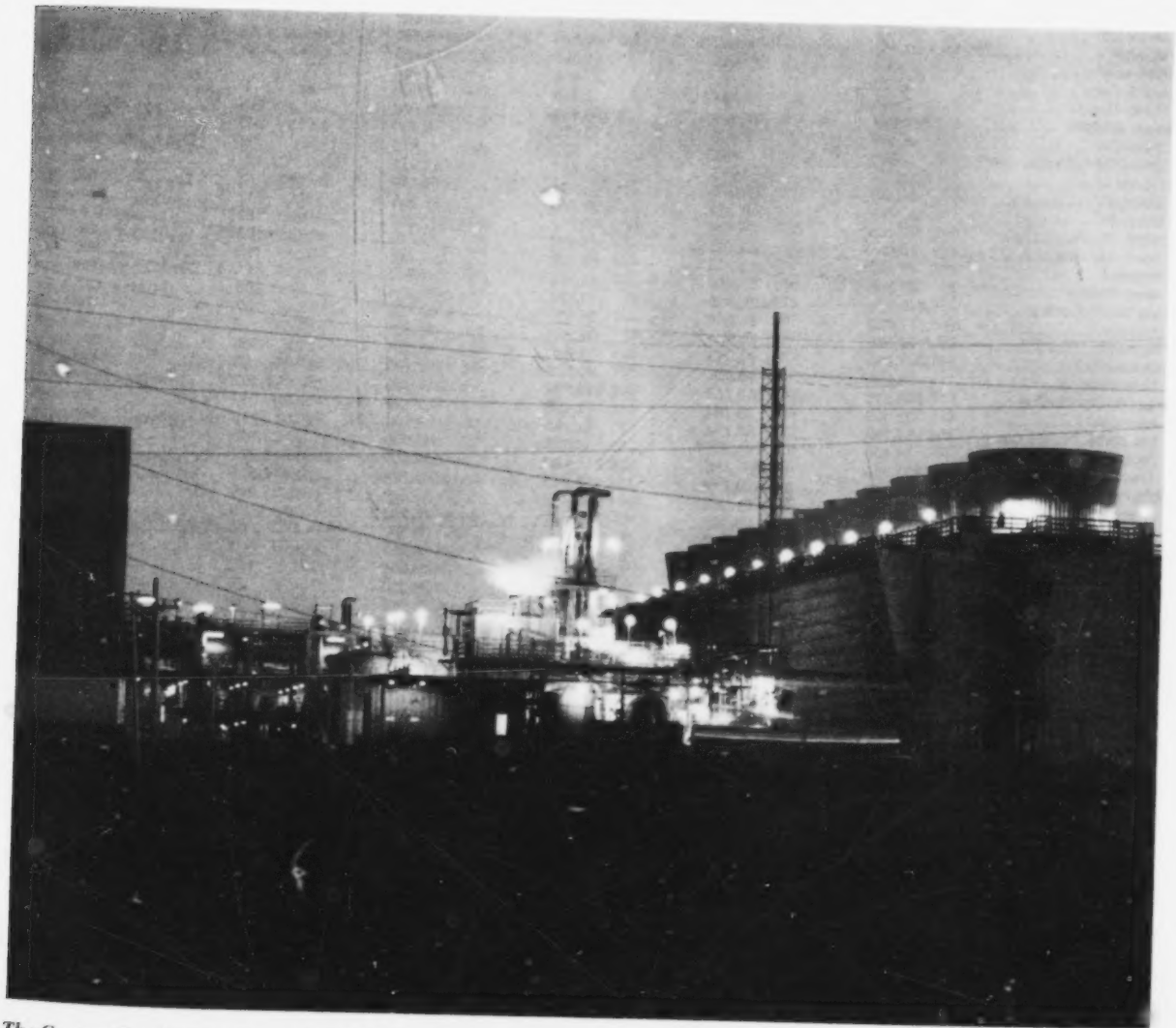
The data in the following tables are aggregated at the national, regional, and State levels for the period 1985 through 1989. Data in the tables were obtained from the Form EIA-759, "Monthly Power Plant Report." The Form EIA-759 is used to collect monthly data from all operators of electric utilities (approximately 800) in the United States. More detailed statistics from the Form EIA-759 are published in the *Electric Power Monthly*.[21]

[21]Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226 (Washington, DC).

Table 12. Net Generation by Energy Source, 1985-1989
(Million Kilowatthours)

Energy Source	1989	1988	1987	1986	1985
Coal	**1,553,661**	**1,540,653**	**1,463,781**	**1,385,831**	**1,402,128**
Petroleum	**158,318**	**148,900**	**118,493**	**136,585**	**100,202**
Steam	151,111	143,801	114,949	133,210	97,490
Gas Turbine/Internal Combustion	7,207	5,099	3,543	3,375	2,712
Gas	**266,598**	**252,801**	**272,621**	**248,508**	**291,946**
Steam	245,057	236,280	257,982	236,484	278,812
Gas Turbine/Internal Combustion	21,542	16,521	14,639	12,024	13,134
Hydroelectric	**265,063**	**222,940**	**249,695**	**290,844**	**281,149**
Nuclear	**529,355**	**526,973**	**455,270**	**414,038**	**383,691**
Other[1]	**11,309**	**11,984**	**12,267**	**11,503**	**10,724**
U.S. Total	**2,784,304**	**2,704,250**	**2,572,127**	**2,487,310**	**2,469,841**

[1] Includes geothermal, wood, wind, waste, and solar.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."



The Geysers Geothermal Powerplant is owned by the Pacific Gas and Electric Company. This plant, located in California, is the largest geothermal facility in the world.

Table 13. Net Generation by Selected Prime Mover, Census Division, and State, 1989 and 1988

(Million Kilowatthours)

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1989	1988	1989	1988	1989	1988
New England	**97,441**	**93,383**	**58,064**	**55,332**	**1,415**	**1,391**
Connecticut	34,277	36,379	13,939	13,483	67	78
Maine	11,624	9,530	2,988	2,928	14	16
Massachusetts	39,158	34,664	34,637	32,173	1,280	1,225
New Hampshire	7,125	6,997	6,018	6,006	19	24
Rhode Island	496	764	478	742	18	22
Vermont	4,761	5,049	5	0	18	26
Middle Atlantic	**326,389**	**317,806**	**211,567**	**203,996**	**4,830**	**3,498**
New Jersey	41,144	40,160	16,481	14,753	1,893	1,738
New York	130,454	124,714	81,450	75,333	2,238	1,304
Pennsylvania	154,790	152,932	113,636	113,910	699	456
East North Central	**482,715**	**465,198**	**359,468**	**354,938**	**410**	**464**
Illinois	126,841	123,340	51,914	54,014	57	112
Indiana	88,563	83,954	88,088	83,482	24	30
Michigan	91,518	88,868	69,241	70,428	216	149
Ohio	131,432	124,034	118,273	114,977	52	65
Wisconsin	44,361	45,003	31,952	32,037	62	107
West North Central	**215,851**	**214,979**	**164,861**	**165,047**	**460**	**617**
Iowa	28,080	27,729	24,204	23,721	41	91
Kansas	34,234	31,385	24,227	24,373	287	351
Minnesota	40,377	40,252	28,519	27,242	31	37
Missouri	59,382	59,740	49,879	49,198	65	96
Nebraska	21,089	20,635	11,820	12,420	33	37
North Dakota	25,705	27,351	23,812	25,468	*	*
South Dakota	6,985	7,886	2,399	2,626	3	5
South Atlantic	**541,877**	**526,309**	**390,438**	**373,668**	**2,798**	**1,425**
Delaware	8,458	8,953	8,255	8,930	203	23
District of Columbia	650	469	592	419	59	50
Florida	124,254	124,053	101,615	96,972	1,489	674
Georgia	92,448	82,375	63,541	65,149	72	65
Maryland	35,759	40,384	30,736	26,908	512	357
North Carolina	87,103	78,406	50,712	46,264	183	106
South Carolina	66,984	65,183	24,082	23,743	107	64
Virginia	43,360	45,172	28,522	24,266	173	86
West Virginia	82,860	81,314	82,384	81,016	*	*
East South Central	**243,374**	**228,905**	**178,504**	**189,591**	**506**	**437**
Alabama	77,600	67,518	52,886	49,100	37	78
Kentucky	70,760	76,436	66,355	74,008	1	5
Mississippi	21,055	25,093	12,840	15,256	389	254
Tennessee	73,959	59,858	46,423	51,226	80	100
West South Central	**364,519**	**355,752**	**319,085**	**316,908**	**7,102**	**6,307**
Arkansas	33,400	33,764	21,458	22,059	13	24
Louisiana	54,292	56,774	41,185	42,294	716	694
Oklahoma	44,448	44,035	38,956	40,000	3,100	1,990
Texas	232,380	221,180	217,485	212,555	3,273	3,598
Mountain	**235,452**	**239,474**	**192,914**	**186,184**	**2,521**	**1,386**
Arizona	53,125	61,562	35,152	29,679	2,246	1,171
Colorado	32,299	30,895	30,041	28,463	23	26
Idaho	8,929	6,746	NA	NA	2	*
Montana	25,823	24,821	16,200	16,526	1	3
Nevada	19,681	20,296	17,693	18,091	129	114
New Mexico	28,349	26,369	28,039	26,200	78	69
Utah	30,496	29,637	29,719	28,866	42	4
Wyoming	36,751	39,147	36,071	38,359	*	*
Pacific Contiguous	**264,349**	**250,622**	**66,902**	**67,355**	**5,314**	**2,953**
California	132,264	125,981	57,863	58,708	3,197	2,806
Oregon	44,964	41,048	444	-31	1,378	-6
Washington	87,121	83,593	8,595	8,678	738	153
Pacific Noncontiguous	**12,336**	**11,822**	**8,024**	**7,715**	**3,392**	**3,142**
Alaska	4,388	4,195	826	728	2,689	2,531
Hawaii	7,949	7,627	7,198	6,987	703	610
U.S. Total	**2,784,304**	**2,704,250**	**1,949,828**	**1,920,734**	**28,749**	**21,620**

* Value less than 0.5 million kilowatthours.

NA = Not applicable.

Notes: •Negative generation denotes that electric power consumed for plant use exceeds gross generation. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table 14. Net Generation by Energy Source, Census Division, and State, 1989 and 1988
(Million Kilowatthours)

Census Division State	Coal		Petroleum		Gas	
	1989	1988	1989	1988	1989	1988
New England	**17,248**	**16,979**	**37,038**	**37,811**	**5,193**	**1,933**
Connecticut	2,095	2,094	11,575	11,356	336	111
Maine	NA	NA	3,002	2,944	NA	NA
Massachusetts	12,088	11,687	19,139	19,908	4,690	1,802
New Hampshire	3,065	3,197	2,970	2,828	1	5
Rhode Island	0	0	333	749	163	15
Vermont	NA	NA	18	26	4	NA
Middle Atlantic	**139,530**	**136,163**	**54,782**	**52,832**	**22,085**	**18,499**
New Jersey	8,392	7,163	5,351	5,052	4,631	4,276
New York	25,224	22,761	41,323	39,865	17,141	14,012
Pennsylvania	105,913	106,239	8,109	7,915	312	211
East North Central	**355,688**	**350,816**	**2,666**	**3,006**	**1,524**	**1,580**
Illinois	51,124	52,994	339	697	508	435
Indiana	87,330	82,813	409	383	374	317
Michigan	67,618	68,578	1,407	1,414	432	585
Ohio	117,819	114,564	442	415	64	63
Wisconsin	31,796	31,867	70	97	147	180
West North Central	**162,278**	**162,491**	**774**	**571**	**2,269**	**2,602**
Iowa	24,041	23,345	43	49	161	417
Kansas	22,907	23,089	109	147	1,498	1,489
Minnesota	27,839	26,726	405	142	306	410
Missouri	49,748	49,051	114	131	82	112
Nebraska	11,582	12,225	57	69	215	163
North Dakota	23,774	25,450	38	18	*	*
South Dakota	2,387	2,605	9	15	6	11
South Atlantic	**332,004**	**323,188**	**40,588**	**35,930**	**20,645**	**15,975**
Delaware	5,066	5,788	2,566	2,848	826	317
District of Columbia	NA	NA	650	469	NA	NA
Florida	59,418	57,516	26,280	25,387	17,407	14,744
Georgia	63,405	64,834	158	260	50	119
Maryland	23,627	23,316	6,044	3,547	1,577	402
North Carolina	50,524	46,090	256	225	115	55
South Carolina	23,800	23,485	134	96	255	226
Virginia	24,059	21,413	4,237	2,838	399	102
West Virginia	82,105	80,747	264	260	16	10
East South Central	**173,875**	**185,856**	**1,156**	**1,079**	**3,980**	**3,092**
Alabama	52,612	48,835	128	107	183	236
Kentucky	66,214	73,847	112	126	29	40
Mississippi	8,724	12,051	738	659	3,767	2,800
Tennessee	46,324	51,122	178	187	1	16
West South Central	**179,374**	**175,455**	**2,803**	**1,200**	**144,011**	**146,560**
Arkansas	18,604	19,876	144	143	2,723	2,065
Louisiana	18,081	18,431	298	272	23,522	24,286
Oklahoma	24,122	24,273	29	29	17,905	17,688
Texas	118,566	112,876	2,332	756	99,861	102,521
Mountain	**184,405**	**180,748**	**781**	**896**	**10,249**	**5,927**
Arizona	32,364	28,391	194	119	4,840	2,341
Colorado	29,406	27,801	30	39	628	649
Idaho	NA	NA	2	*	0	0
Montana	16,129	16,462	30	30	43	37
Nevada	15,382	16,764	377	542	2,063	899
New Mexico	25,446	24,245	41	45	2,630	1,979
Utah	29,676	28,806	48	59	37	5
Wyoming	36,003	38,279	59	62	9	18
Pacific Contiguous	**8,959**	**8,641**	**9,447**	**7,622**	**53,810**	**54,045**
California	NA	NA	9,327	7,621	51,734	53,893
Oregon	440	-30	35	-7	1,347	0
Washington	8,519	8,670	85	8	729	153
Pacific Noncontiguous	**302**	**316**	**8,283**	**7,953**	**2,832**	**2,588**
Alaska	302	316	381	356	2,832	2,588
Hawaii	NA	NA	7,902	7,597	0	0
U.S. Total	**1,553,66[1]**	**1,540,653**	**158,318**	**148,900**	**266,598**	**252,801**

* Value less than 0.5 million kilowatthours.
NA = Not applicable.
Notes: •Negative generation denotes that electric power consumed for plant use exceeds gross generation. •Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table 14. Net Generation by Energy Source, Census Division, and State, 1989 and 1988 (Continued)

(Million Kilowatthours)

Census Division State	Nuclear		Hydroelectric[1]		Other[2]	
	1989	1988	1989	1988	1989	1988
New England	**33,126**	**32,499**	**4,334**	**3,819**	**502**	**342**
Connecticut	19,563	22,251	390	324	317	242
Maine	6,942	5,017	1,681	1,569	NA	NA
Massachusetts	3,015	1,117	226	150	NA	NA
New Hampshire	NA	NA	1,089	968	NA	NA
Rhode Island	NA	NA	0	0	NA	NA
Vermont	3,607	4,114	948	809	184	100
Middle Atlantic	**85,045**	**85,928**	**24,947**	**24,384**	**NA**	**0**
New Jersey	23,032	23,890	-261	-222	NA	NA
New York	22,847	24,175	23,918	23,901	NA	0
Pennsylvania	39,166	37,862	1,290	705	NA	NA
East North Central	**119,641**	**106,893**	**2,698**	**2,389**	**498**	**514**
Illinois	74,820	69,166	50	48	NA	NA
Indiana	NA	NA	450	441	NA	NA
Michigan	21,312	17,808	749	483	0	0
Ohio	12,661	8,455	130	187	316	351
Wisconsin	10,848	11,464	1,319	1,230	181	164
West North Central	**40,196**	**37,865**	**10,064**	**11,240**	**271**	**210**
Iowa	3,139	3,163	672	698	24	57
Kansas	9,709	6,650	10	12	*	*
Minnesota	10,926	12,288	654	532	247	153
Missouri	8,344	8,935	1,094	1,511	NA	NA
Nebraska	8,077	6,828	1,158	1,350	NA	NA
North Dakota	NA	NA	1,893	1,884	NA	0
South Dakota	NA	NA	4,583	5,254	NA	NA
South Atlantic	**132,852**	**144,010**	**15,775**	**7,149**	**14**	**57**
Delaware	NA	NA	NA	NA	NA	NA
District of Columbia	NA	NA	NA	NA	NA	NA
Florida	20,916	26,198	234	209	NA	0
Georgia	24,961	15,149	3,874	2,011	NA	NA
Maryland	2,719	11,734	1,778	1,328	14	57
North Carolina	29,212	29,146	6,996	2,890	NA	NA
South Carolina	40,780	40,746	2,016	631	NA	NA
Virginia	14,264	21,037	401	-218	*	*
West Virginia	NA	NA	476	297	NA	NA
East South Central	**34,954**	**26,504**	**29,410**	**12,374**	**NA**	**NA**
Alabama	11,524	12,981	13,153	5,359	NA	NA
Kentucky	NA	NA	4,404	2,423	NA	NA
Mississippi	7,826	9,582	NA	NA	NA	NA
Tennessee	15,503	3,940	11,853	4,591	NA	NA
West South Central	**31,225**	**26,473**	**6,917**	**6,065**	**190**	**0**
Arkansas	8,844	8,895	3,084	2,785	NA	NA
Louisiana	12,391	13,785	NA	NA	NA	NA
Oklahoma	NA	NA	2,392	2,045	NA	NA
Texas	9,990	3,792	1,441	1,235	190	0
Mountain	**8,380**	**23,600**	**31,392**	**28,072**	**246**	**232**
Arizona	7,850	22,940	7,877	7,771	NA	NA
Colorado	529	660	1,705	1,744	1	2
Idaho	NA	NA	8,927	6,745	NA	NA
Montana	NA	NA	9,550	8,237	72	55
Nevada	NA	NA	1,859	2,091	NA	NA
New Mexico	NA	NA	232	100	NA	NA
Utah	NA	NA	562	593	173	174
Wyoming	NA	NA	680	789	*	*
Pacific Contiguous	**43,936**	**43,202**	**138,633**	**126,499**	**9,565**	**10,613**
California	32,519	30,863	29,524	23,474	9,161	10,131
Oregon	5,299	6,339	37,815	34,646	28	99
Washington	6,118	6,000	71,293	68,379	376	383
Pacific Noncontiguous	**NA**	**NA**	**895**	**950**	**25**	**16**
Alaska	NA	NA	873	935	0	0
Hawaii	NA	NA	22	14	25	16
U.S. Total	**529,355**	**526,973**	**265,063**	**222,940**	**11,309**	**11,984**

[1] Station losses include energy used for pumped storage. Energy used in 1989 for pumping was 24,964 million kilowatthours and in 1988 was 23,935 million kilowatthours.

[2] Includes geothermal, wood, wind, waste, and solar.

* Value less than 0.5 million kilowatthours.

NA = Not applicable.

Notes: •Negative generation denotes that electric power consumed for plant use exceeds gross generation. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table 15. Petroleum-Fired Net Generation by Selected Prime Mover, Census Division, and State, 1989 and 1988

(Million Kilowatthours)

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1989	1988	1989	1988	1989	1988
New England	**37,038**	**37,811**	**36,113**	**36,923**	**925**	**888**
Connecticut	11,575	11,356	11,508	11,278	67	78
Maine	3,002	2,944	2,988	2,928	14	16
Massachusetts	19,139	19,908	18,348	19,182	791	726
New Hampshire	2,970	2,828	2,953	2,809	18	19
Rhode Island	333	749	315	727	18	22
Vermont	18	26	1	0	18	26
Middle Atlantic	**54,782**	**52,832**	**52,007**	**51,043**	**2,776**	**1,790**
New Jersey	5,351	5,052	4,553	4,453	798	599
New York	41,323	39,865	39,883	39,052	1,439	813
Pennsylvania	8,109	7,915	7,571	7,538	539	378
East North Central	**2,666**	**3,006**	**2,558**	**2,804**	**108**	**202**
Illinois	339	697	326	646	13	51
Indiana	409	383	404	377	5	6
Michigan	1,407	1,414	1,379	1,365	28	49
Ohio	442	415	410	370	32	45
Wisconsin	70	97	40	46	30	51
West North Central	**774**	**571**	**667**	**450**	**107**	**121**
Iowa	43	49	29	31	14	18
Kansas	109	147	66	117	43	30
Minnesota	405	142	398	122	7	20
Missouri	114	131	87	89	27	42
Nebraska	57	69	43	62	13	7
North Dakota	38	18	37	18	*	*
South Dakota	9	15	6	11	3	4
South Atlantic	**40,588**	**35,930**	**38,850**	**35,078**	**1,738**	**852**
Delaware	2,566	2,848	2,523	2,825	42	23
District of Columbia	650	469	592	419	59	50
Florida	26,280	25,387	25,390	25,058	889	329
Georgia	158	260	95	207	63	54
Maryland	6,044	3,547	5,660	3,290	384	258
North Carolina	256	225	166	174	90	51
South Carolina	134	96	75	71	59	25
Virginia	4,237	2,838	4,086	2,775	151	63
West Virginia	264	260	263	260	*	*
East South Central	**1,156**	**1,079**	**1,044**	**988**	**111**	**91**
Alabama	128	107	98	104	30	3
Kentucky	112	126	112	124	*	2
Mississippi	738	659	735	657	3	2
Tennessee	178	187	99	103	79	84
West South Central	**2,803**	**1,200**	**2,631**	**1,099**	**171**	**101**
Arkansas	144	143	131	121	13	22
Louisiana	298	272	296	268	1	4
Oklahoma	29	29	26	26	3	3
Texas	2,332	756	2,177	685	154	72
Mountain	**781**	**896**	**714**	**868**	**67**	**28**
Arizona	194	119	157	117	37	2
Colorado	30	39	23	35	8	4
Idaho	2	*	NA	NA	2	*
Montana	30	30	29	27	*	3
Nevada	377	542	362	527	15	16
New Mexico	41	45	40	43	1	1
Utah	48	59	45	57	4	2
Wyoming	59	62	59	62	*	*
Pacific Contiguous	**9,447**	**7,622**	**9,328**	**7,560**	**120**	**62**
California	9,327	7,621	9,252	7,554	75	67
Oregon	35	-7	4	-1	31	-6
Washington	85	8	71	7	14	1
Pacific Noncontiguous	**8,283**	**7,953**	**7,199**	**6,987**	**1,084**	**966**
Alaska	381	356	*	*	381	356
Hawaii	7,902	7,597	7,198	6,987	703	610
U.S. Total	**158,318**	**148,900**	**151,111**	**143,801**	**7,207**	**5,099**

* Value less than 0.5 million kilowatthours.

NA = Not applicable.

Notes: •Negative generation denotes that electric power consumed for plant use exceeds gross generation. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table 16. Gas-Fired Net Generation by Selected Prime Mover, Census Division, and State, 1989 and 1988

(Million Kilowatthours)

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1989	1988	1989	1988	1989	1988
New England	**5,193**	**1,933**	**4,703**	**1,430**	**490**	**503**
Connecticut	336	111	336	111	NA	NA
Maine	NA	NA	NA	NA	NA	NA
Massachusetts	4,690	1,802	4,201	1,304	489	498
New Hampshire	1	5	NA	NA	1	5
Rhode Island	163	15	163	15	NA	NA
Vermont	4	NA	4	NA	NA	NA
Middle Atlantic	**22,085**	**18,499**	**20,030**	**16,791**	**2,055**	**1,708**
New Jersey	4,631	4,276	3,536	3,137	1,095	1,139
New York	17,141	14,012	16,343	13,520	799	492
Pennsylvania	312	211	152	133	161	78
East North Central	**1,524**	**1,580**	**1,222**	**1,318**	**302**	**262**
Illinois	508	435	465	374	44	61
Indiana	374	317	354	293	19	24
Michigan	432	585	244	485	188	100
Ohio	64	63	44	43	20	21
Wisconsin	147	180	115	124	31	56
West North Central	**2,269**	**2,602**	**1,916**	**2,106**	**353**	**496**
Iowa	161	417	135	344	27	73
Kansas	1,498	1,489	1,254	1,167	245	321
Minnesota	306	410	283	393	24	17
Missouri	82	112	44	58	38	54
Nebraska	215	163	195	133	20	30
North Dakota	*	*	*	*	*	*
South Dakota	6	11	7	10	*	1
South Atlantic	**20,645**	**15,975**	**19,584**	**15,402**	**1,060**	**573**
Delaware	826	317	665	317	160	NA
District of Columbia	NA	NA	NA	NA	NA	NA
Florida	17,407	14,744	16,807	14,399	600	345
Georgia	50	119	41	108	9	11
Maryland	1,577	402	1,449	303	128	100
North Carolina	115	55	22	NA	93	55
South Carolina	255	226	207	187	48	39
Virginia	399	102	377	78	22	23
West Virginia	16	10	16	10	NA	NA
East South Central	**3,[illegible]0**	**3,092**	**3,585**	**2,746**	**395**	**346**
Alabama	1[illegible]	236	176	161	7	75
Kentucky	29	40	28	37	1	3
Mississippi	3,767	2,800	3,381	2,549	386	252
Tennessee	1	16	*	*	1	16
West South Central	**144,011**	**146,560**	**137,080**	**140,354**	**6,930**	**6,206**
Arkansas	2,723	2,065	2,723	2,063	*	2
Louisiana	23,522	24,286	22,808	23,596	714	690
Oklahoma	17,905	17,688	14,808	15,701	3,097	1,987
Texas	99,861	102,521	96,742	98,994	3,119	3,526
Mountain	**10,249**	**5,927**	**7,795**	**4,568**	**2,455**	**1,359**
Arizona	4,840	2,341	2,631	1,172	2,209	1,169
Colorado	628	649	613	627	15	22
Idaho	0	0	NA	NA	0	0
Montana	43	37	42	37	*	*
Nevada	2,063	899	1,949	801	114	98
New Mexico	2,630	1,979	2,553	1,912	77	67
Utah	37	5	-2	3	38	2
Wyoming	9	18	9	18	NA	NA
Pacific Contiguous	**53,810**	**54,045**	**48,616**	**51,154**	**5,194**	**2,892**
California	51,734	53,893	48,611	51,154	3,123	2,739
Oregon	1,347	0	NA	NA	1,347	0
Washington	729	153	5	0	724	153
Pacific Noncontiguous	**2,832**	**2,588**	**523**	**412**	**2,309**	**2,176**
Alaska	2,832	2,588	523	412	2,309	2,176
Hawaii	0	0	0	0	NA	NA
U.S. Total	**266,598**	**252,801**	**245,057**	**236,280**	**21,542**	**16,521**

* Value less than 0.5 million kilowatthours.

NA = Not applicable.

Notes: •Negative generation denotes that electric power consumed for plant use exceeds gross generation. •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Fossil-Fuel Statistics

This chapter contains statistics on the consumption of fossil fuels used to generate electricity, end-of-year fossil-fuel stocks for all electric utility plants, and the receipts and costs of fossil fuels at steam-electric power plants with a nameplate capacity of 50 or more megawatts. These data are aggregated to the national, Census division, and State levels.

Background

Various sources of energy are used by the electric power industry to produce electricity; however, fossil fuels supply about 70 percent of the energy sources for the generation requirements of the Nation. Fossil fuels are so named because they are derived from the remains of the plants and animals, which lived on earth millions of years ago. Coal, petroleum, and gas are currently the dominant fossil fuels used by the industry. Other fossil fuels include petroleum coke, refinery gas, coke oven gas, blast furnace gas, and liquified petroleum gas. Statistics on consumption, purchases (receipts), and stocks of fossil fuels at electric utilities are interdependent. That is, the stocks on site at the utility at the end of the current year result from the stocks that were available at the end of the prior year, the amount of fuel purchased during the current year, and the amount of fuel consumed during the year.

Fossil-Fuel Consumption and Stocks

Coal, the energy source used to generate more than one-half of the electricity needed in the Nation, is consumed extensively throughout the United States (particularly in the East North Central, West North Central, West South Central, and the South Atlantic Census Divisions). The use of petroleum for generation is not as common on a national level as during the early 1970's; however, some areas of the country (such as in California, as well as in the New England and Pacific Noncontiguous Census Divisions) continue to use it extensively. Consumption of gas occurs mostly in areas of the country where it is readily accessible, particularly in the West South Central Census Division, and in dual-fired generator units, which use gas and petroleum as substitute fuels.

The purposes of on-site storage are to provide an uninterrupted supply, allow bulk shipments, and take advantage of favorable market conditions. Since gas is generally not stored, there are no stocks of gas. Electric utilities maintain stockpiles of coal and petroleum to minimize the effect of an interruption or curtailment in fuel availability (for example, railroad strikes, coalmine strikes, or oil embargoes).

Fossil-Fuel Receipts and Costs

Statistics on receipts provide information regarding the delivery of fossil fuels to steam-electric plants. The costs include all costs incurred by an electric utility in the purchase and delivery of fuel to the plant. The type of contract under which a fuel is purchased has a significant effect on the cost of the fuel delivered and can be used as a good indicator of market conditions. Transactions where petroleum and coal are obtained by the utility under purchase orders or contracts of more than 1-year duration are referred to as *contract purchases*. Shipments of petroleum and coal under purchase orders or contracts of less than 1-year duration are considered *spot purchases*. Transactions to secure gas that are conducted under a contract with uninterrupted delivery are identified as *firm purchases*. *Interruptible purchases* are those in which the gas is received under a contract that permits curtailment of service under certain circumstances. For example, under both Federal and State regulations, requirements for gas to heat homes and serve industry have priority over requirements of the electric power industry. Consequently, a contract under which gas is purchased is most generally one that allows for an interruption in its accessibility. A contract under which gas is purchased and delivered only at a specified time of the year is an *off-peak purchase*.

Coal. Coal is obtained from three major coal-producing areas in the United States. *Appalachian coal* is mined in both surface and underground mines located in Pennsylvania, Maryland, Virginia, West Virginia, eastern Kentucky, Tennessee, Alabama, and Ohio. This coal is bituminous in rank and of low-to-medium sulfur content. Its heat content in British Thermal Units (Btu) averages over 12,000 Btu per pound. The coal is transported primarily by train, barge, and truck to electric plants throughout the eastern United States. *Interior coal* is mined in both surface and underground mines located in Illinois, Indiana, western Kentucky, and Missouri. It is bituminous coal with a high percentage of sulfur and ash and contains approximately 11,000 Btu per pound. Most of this coal is delivered to electric

plants in the central United States. *Western coal* is mined in Montana, Wyoming, Colorado, Utah, North Dakota, Arizona, and New Mexico. It is delivered to electric plants throughout the western and central United States. Over one-half of the coal in this region is subbituminous coal that is low in sulfur content (less than 0.5 percent per pound) and contains approximately 8,000 Btu per pound. This coal originates in the Powder River basin of northeast Wyoming and southeast Montana. Coal from this region is delivered by unit train to electric plants as far east as Ohio and Georgia.

The cost of coal delivered to electric utilities can vary significantly from State to State. Coal delivered to the New England Census Division from the Appalachian coal fields may cost as much as $60.00 per short ton due to transportation costs and the higher cost of producing eastern coal, which is generally in underground mines. Environmental restrictions within a State may require electric utilities to burn only the more expensive, low-sulfur coal resulting in a higher delivered cost. In the West, especially in the Mountain Census Division, coal-burning plants are often built in close proximity to the mine thus reducing transportation costs. In addition, the cost of mining coal from the large surface mines located in the western United States is significantly less than that of underground eastern mines, resulting in a delivered cost of under $15.00 per short ton for States such as Montana and Wyoming. In States such as North Dakota, South Dakota, and Texas, the cost of coal delivered to electric utilities is well below the national average because of the lower cost of low-grade lignite.

Petroleum. Although nationwide receipts at electric utilities are less than one-half the volume of the 1970's, several electric utilities in the New England area, and in New York, Florida, California, and Hawaii still depend on petroleum for a significant portion of their fossil-fuel requirements. Receipts can vary widely from year to year at electric utilities due to changes in the cost of petroleum. Fuel oil Numbers 2, 4, 5, and 6 are purchased by electric utilities for use in generating electricity. Fuel oil Numbers 4, 5, and 6 (heavy oil) constitute the majority of all petroleum receipts at electric utilities. Smaller amounts of fuel oil Number 2 (light oil) are also used by electric utilities primarily for start-up and flame stabilization of the boilers.

The cost of petroleum delivered to electric utilities varies considerably from State to State. The most important factor in determining cost is the type of fuel oil that is being delivered. States receiving only low-grade heavy oil will show a delivered cost much lower than a State receiving only light oil. Most of the petroleum delivered to the New England, Middle Atlantic, and South Atlantic Census Divisions, California, and Hawaii for use by electric utilities is the Number 6 fuel oil. The cost of fuel oil can vary because of its sulfur content. Electric utilities that are required to meet stringent environmental standards must purchase low-sulfur fuel oil at premium prices.

Gas. Gas is used extensively as a primary fuel throughout areas of the country where it is readily accessible, for example, the West South Central Census Division and in California. Large volumes of gas are also transported by pipeline to the Middle Atlantic, and South Atlantic Census Divisions. Gas receipts to these Census divisions and to California can vary considerably from year to year because some electric utilities switch between use of petroleum and gas in dual-fired generating units. The highest volume of gas receipts at electric utilities occurs during the summer months when demand for electricity peaks and when there is a greater amount available to electric utilities because of lower demands from residential and commercial consumers. In some northern parts of the United States, receipts of gas at electric utilities are limited during the winter months due to the priority for heating and industry needs. Many electric utilities have the capability of burning either petroleum or gas. The cost of the fuel is usually the determining factor. One major advantage of gas over all other fossil fuels is that it is a clean burning fuel. Therefore, some electric utilities use gas in order to comply with environmental regulations.

Petroleum Coke. Petroleum coke is the final product or residue produced from the process of breaking down complex petroleum hydrocarbons into lighter petroleum products such as gasoline (cracking).

Data Sources

Data in the following tables were obtained from two sources. The first is the Form EIA-759, "Monthly Power Plant Report," which is used to collect monthly data from all operators of electric utilities (approximately 800) in the United States. More detailed statistics on stocks and consumption are published in the *Electric Power Monthly*.[22] The second source is the Federal Energy Regulatory Commission (FERC) Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," which is a restricted-universe census used to collect data from approximately 225 electric utilities. More detailed statistics on receipts and costs of fossil fuels are published in the *Cost and Quality of Fuels for Electric Utility Plants*.[23] Caution should be used in comparing stocks, receipts, and consumption data since all operators of power plants are surveyed by the Form EIA-759, while the FERC Form 423 is limited to operators of power plants with a fossil-fueled steam-electric nameplate capacity of 50 or more megawatts.

[22]Energy Information Administration, *Electric Power Monthly*, DOE/EIA-0226(Washington, DC).
[23]Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants* DOE/EIA-0191(89)(Washington, DC, July 1990).

Table 17. Consumption of Fossil Fuels, and Stocks of Coal and Petroleum, 1985-1989

Item	1989	1988	1987	1986	1985
Consumption					
Coal (thousand short tons)	766,888	758,372	717,894	685,056	693,841
Petroleum (thousand barrels)[1]	267,451	248,096	199,378	230,482	173,414
Gas (million cubic feet)	2,787,012	2,635,613	2,844,051	2,602,370	3,044,083
Stocks[2]					
Coal (thousand short tons)	135,860	146,507	170,797	161,806	156,376
Petroleum (thousand barrels)[1]	61,270	69,285	70,827	73,111	73,689

[1] Does not include petroleum coke.
[2] Stocks are shown as of December 31 of each year.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table 18. Receipts and Average Delivered Cost of Fossil Fuels, 1985-1989

Item	1989	1988	1987	1986	1985
Receipts					
Coal (thousand short tons)	753,217	727,775	721,298	686,964	666,743
Petroleum (thousand barrels)[1]	246,422	236,923	194,578	228,522	164,946
Gas (million cubic feet)	2,472,506	2,362,721	2,605,191	2,387,622	2,808,921
Cost (dollars)					
Coal (per short ton)	R 30.15	30.64	31.83	33.30	34.53
Contract	R 30.38	30.86	32.01	33.51	34.63
Spot	R 29.07	29.30	30.86	31.81	33.73
Petroleum (per barrel)[1]	18.17	15.33	19.06	15.30	27.08
Contract	18.17	15.36	19.15	15.56	27.18
Spot	18.17	15.25	18.73	14.54	26.44
Gas (per thousand cubic feet)	2.42	2.33	2.31	2.43	3.58
Firm	2.34	2.22	2.31	2.41	3.20
Interruptible[2]	2.50	2.47	2.32	2.47	4.11

[1] Does not include petroleum coke.
[2] Includes off-peak gas.
R = Revised data.
Notes: •Data are for plants with a fossil-fueled steam-electric nameplate capacity of 50 or more megawatts. •Totals may not equal sum of components because of independent rounding.
Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

The average cost of coal includes the cost of transporting the coal from the mine to the utility.

Table 19. Consumption of Fossil Fuels by Census Division and State, 1989 and 1988

Census Division State	Coal (thousand short tons)		Petroleum[1] (thousand barrels)		Gas (million cubic feet)	
	1989	1988	1989	1988	1989	1988
New England	**6,510**	**6,330**	**61,320**	**62,087**	**53 949**	**21,374**
Connecticut	877	854	19,074	18,500	3,294	1,260
Maine	NA	NA	5,069	4,906	NA	NA
Massachusetts	4,474	4,260	31,279	32,198	48,448	19,874
New Hampshire	1,160	1,217	5,135	4,870	23	55
Rhode Island	0	0	713	1,538	2,147	185
Vermont	NA	NA	50	75	37	NA
Middle Atlantic	**56,642**	**55,059**	**91,461**	**86,859**	**241,435**	**202,208**
New Jersey	3,244	2,773	9,982	9,204	55,412	51,066
New York	10,158	9,120	68,272	65,002	182,000	148,493
Pennsylvania	43,241	43,166	13,207	12,653	4,022	2,649
East North Central	**166,437**	**163,462**	**6,538**	**7,002**	**32,883**	**27,901**
Illinois	25,758	26,681	1,990	2,559	6,967	5,706
Indiana	42,378	40,060	370	379	4,075	3,455
Michigan	29,972	29,968	2,991	2,915	18,782	15,027
Ohio	50,479	48,893	1,018	921	983	974
Wisconsin	17,851	17,861	168	229	2,076	2,739
West North Central	**101,213**	**101,097**	**920**	**1,126**	**29,948**	**33,459**
Iowa	14,598	13,921	112	123	2,402	5,459
Kansas	14,774	14,742	246	283	19,152	18,890
Minnesota	17,056	16,259	89	137	4,427	5,217
Missouri	24,663	24,356	257	339	1,242	1,623
Nebraska	7,303	7,744	110	140	2,593	2,046
North Dakota	20,538	21,686	72	46	1	2
South Dakota	2,281	2,388	33	58	132	223
South Atlantic	**132,285**	**128,628**	**68,452**	**58,853**	**222,979**	**168,894**
Delaware	2,128	2,420	3,457	4,365	7,999	2,824
District of Columbia	NA	NA	1,490	1,100	NA	NA
Florida	24,292	23,528	42,966	40,660	186,814	154,550
Georgia	25,839	26,513	346	494	684	1,569
Maryland	9,074	9,020	11,662	6,866	19,184	5,336
North Carolina	19,516	17,766	557	458	1,673	1,068
South Carolina	9,472	9,210	285	195	2,705	2,378
Virginia	9,573	8,469	6,786	4,357	3,796	1,096
West Virginia	32,391	31,704	402	356	124	73
East South Central	**73,842**	**77,689**	**2,164**	**1,906**	**47,033**	**36,512**
Alabama	21,884	20,002	216	174	1,760	2,574
Kentucky	29,109	31,818	230	202	328	452
Mississippi	3,566	4,859	1,363	1,166	44,927	33,261
Tennessee	19,283	21,010	356	365	18	225
West South Central	**124,171**	**121,919**	**5,116**	**2,252**	**1,476,260**	**1,493,530**
Arkansas	11,278	12,295	278	265	29,462	22,075
Louisiana	11,770	12,301	521	543	244,984	250,323
Oklahoma	14,423	14,435	62	60	178,021	177,222
Texas	86,701	82,889	4,255	1,384	1,023,793	1,043,910
Mountain	**99,670**	**98,351**	**1,454**	**1,628**	**110,815**	**66,203**
Arizona	16,182	13,932	361	219	50,807	25,328
Colorado	15,686	15,087	71	84	8,375	8,488
Idaho	NA	NA	4	1	0	0
Montana	10,208	10,410	60	63	336	286
Nevada	7,487	8,153	669	945	23,210	10,658
New Mexico	15,250	14,661	84	94	27,365	21,064
Utah	12,949	12,544	86	103	636	196
Wyoming	21,908	23,563	118	121	85	183
Pacific Contiguous	**5,820**	**5,561**	**15,639**	**12,649**	**538,963**	**554,691**
California	NA	NA	15,370	12,631	517,700	552,938
Oregon	306	0	76	1	12,942	0
Washington	5,514	5,561	192	16	8,320	1,753
Pacific Noncontiguous	**299**	**276**	**14,387**	**13,732**	**32,746**	**30,841**
Alaska	299	276	736	688	32,746	30,841
Hawaii	NA	NA	13,651	13,044	0	0
U.S. Total	**766,888**	**758,372**	**267,451**	**248,096**	**2,787,012**	**2,635,613**

[1] Does not include petroleum coke. Petroleum coke consumption in 1989 was 517 thousand short tons and in 1988 was 409 thousand short tons.
NA = Not applicable.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table 20. Petroleum Consumption by Selected Prime Mover, Census Division, and State, 1989 and 1988

(Thousand Barrels)

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1989	1988	1989	1988	1989	1988
New England	**61,320**	**62,087**	**59,377**	**60,179**	1,943	1,908
Connecticut	19,074	18,500	18,906	18,304	16e	197
Maine	5,069	4,906	5,034	4,868	34	38
Massachusetts	31,279	32,198	29,662	30,684	1,618	1,514
New Hampshire	5,135	4,870	5,092	4,821	43	49
Rhode Island	713	1,538	679	1,496	35	42
Vermont	50	75	4	6	46	69
Middle Atlantic	**91,461**	**86,859**	**84,690**	**82,400**	6,772	4,459
New Jersey	9,982	9,204	8,021	7,721	1,961	1,483
New York	68,272	65,002	64,747	62,983	3,525	2,019
Pennsylvania	13,207	12,653	11,922	11,696	1,285	957
East North Central	**6,538**	**7,002**	**6,120**	**6,353**	417	649
Illinois	1,990	2,559	1,948	2,393	42	166
Indiana	370	379	353	361	17	18
Michigan	2,991	2,915	2,841	2,742	151	173
Ohio	1,018	921	900	772	118	149
Wisconsin	168	229	79	86	89	143
West North Central	**920**	**1,126**	**581**	**705**	339	421
Iowa	112	123	66	58	46	65
Kansas	246	283	137	213	108	70
Minnesota	89	137	59	59	31	78
Missouri	257	339	157	170	100	169
Nebraska	110	140	74	120	36	21
North Dakota	72	46	71	45	1	1
South Dakota	33	58	16	40	17	18
South Atlantic	**68,452**	**58,853**	**64,068**	**56,625**	4,384	2,228
Delaware	3,957	4,365	3,815	4,309	142	57
District of Columbia	1,490	1,100	1,322	952	168	148
Florida	42,966	40,660	40,858	39,855	2,108	806
Georgia	346	494	168	349	178	145
Maryland	11,662	6,866	10,741	6,241	921	625
North Carolina	557	458	269	277	288	181
South Carolina	285	195	118	103	167	92
Virginia	6,786	4,357	6,376	4,185	410	172
West Virginia	402	356	401	354	1	2
East South Central	**2,164**	**1,906**	**1,900**	**1,673**	264	234
Alabama	216	174	156	162	60	12
Kentucky	230	202	226	194	4	7
Mississippi	1,363	1,166	1,355	1,160	8	6
Tennessee	356	365	164	157	192	208
West South Central	**5,116**	**2,252**	**4,780**	**2,057**	336	195
Arkansas	278	265	247	216	31	50
Louisiana	521	543	515	535	6	8
Oklahoma	62	60	57	53	6	6
Texas	4,255	1,384	3,962	1,253	293	131
Mountain	**1,454**	**1,628**	**1,296**	**1,553**	158	75
Arizona	361	219	287	214	74	5
Colorado	71	84	49	72	22	12
Idaho	4	1	NA	NA	4	* 1
Montana	60	63	59	57	1	6
Nevada	669	945	624	902	45	43
New Mexico	84	94	81	90	3	4
Utah	86	103	77	98	8	5
Wyoming	118	121	118	121	0	0
Pacific Contiguous	**15,639**	**12,649**	**15,245**	**12,479**	394	169
California	15,370	12,631	15,072	12,464	299	167
Oregon	76	1	9	0	67	1
Washington	192	16	164	15	28	2
Pacific Noncontiguous	**14,387**	**13,732**	**12,258**	**11,791**	2,129	1,940
Alaska	736	688	1	*	735	687
Hawaii	13,651	13,044	12,257	11,791	1,394	1,253
U.S. Total	**267,451**	**248,096**	**250,315**	**235,817**	17,136	12,279

* Value less than 0.5.

NA = Not applicable.

Notes: •Totals may not equal sum of components because of independent rounding. •Does not include petroleum coke. Petroleum coke consumption in 1989 was 517 thousand short tons and in 1988 was 409 thousand short tons.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table 21. Gas Consumption by Selected Prime Mover, Census Division, and State, 1989 and 1988

(Million Cubic Feet)

Census Division State	Total		Steam		Gas Turbine/Internal Combustion	
	1989	1988	1989	1988	1989	1988
New England	**53,949**	**21,374**	**48,157**	**15,160**	5,792	6,214
Connecticut	3,294	1,260	3,294	1,260	NA	NA
Maine	NA	NA	NA	NA	NA	NA
Massachusetts	48,448	19,874	42,678	13,715	5,770	6,159
New Hampshire	23	55	NA	NA	23	55
Rhode Island	2,147	185	2,147	185	NA	NA
Vermont	37	NA	37	NA	NA	NA
Middle Atlantic	**241,435**	**202,208**	**211,174**	**177,239**	30,261	24,968
New Jersey	55,412	51,066	39,952	34,901	15,460	16,165
New York	182,000	148,493	169,657	140,939	12,343	7,554
Pennsylvania	4,022	2,649	1,564	1,400	2,458	1,249
East North Central	**32,883**	**27,901**	**28,968**	**23,983**	3,915	3,919
Illinois	6,967	5,706	6,410	4,885	557	821
Indiana	4,075	3,455	3,809	3,076	266	379
Michigan	18,782	15,027	16,603	13,764	2,179	1,263
Ohio	983	974	559	477	424	497
Wisconsin	2,076	2,739	1,587	1,780	489	959
West North Central	**29,948**	**33,459**	**25,049**	**26,642**	4,899	6,817
Iowa	2,402	5,459	1,989	4,356	413	1,103
Kansas	19,152	18,890	16,067	14,790	3,085	4,101
Minnesota	4,427	5,217	3,974	4,963	453	254
Missouri	1,242	1,623	570	721	671	901
Nebraska	2,593	2,046	2,321	1,621	272	425
North Dakota	1	2	*	*	*	2
South Dakota	132	223	127	191	5	32
South Atlantic	**222,979**	**168,894**	**207,593**	**160,428**	15,387	8,466
Delaware	7,999	2,824	6,202	2,824	1,796	NA
District of Columbia	NA	NA	NA	NA	NA	NA
Florida	186,814	154,550	178,163	150,039	8,652	4,511
Georgia	684	1,569	515	1,380	168	189
Maryland	19,184	5,336	17,193	3,775	1,991	1,561
North Carolina	1,673	1,068	0	NA	1,673	1,068
South Carolina	2,705	2,378	1,881	1,644	825	734
Virginia	3,796	1,096	3,515	693	281	403
West Virginia	124	73	124	73	NA	NA
East South Central	**47,033**	**36,512**	**39,454**	**31,235**	7,579	5,277
Alabama	1,760	2,574	1,648	1,538	113	1,036
Kentucky	328	452	314	390	14	62
Mississippi	44,927	33,261	37,493	29,308	7,434	3,953
Tennessee	18	225	0	0	18	225
West South Central	**1,476,260**	**1,493,530**	**1,402,180**	**1,416,718**	74,080	76,812
Arkansas	29,462	22,075	29,462	22,037	*	38
Louisiana	244,984	250,323	236,836	243,042	8,148	7,281
Oklahoma	178,021	177,222	150,153	152,728	27,867	24,494
Texas	1,023,793	1,043,910	985,729	998,911	38,064	44,999
Mountain	**110,815**	**66,203**	**84,327**	**51,130**	26,488	15,072
Arizona	50,807	25,328	28,382	13,013	22,426	12,315
Colorado	8,375	8,488	8,100	8,151	275	336
Idaho	0	0	NA	NA	0	0
Montana	336	286	327	278	9	8
Nevada	23,210	10,658	21,000	9,149	2,210	1,510
New Mexico	27,365	21,064	26,433	20,261	932	803
Utah	636	196	0	95	636	101
Wyoming	85	183	85	183	NA	NA
Pacific Contiguous	**538,963**	**554,691**	**483,212**	**509,804**	55,751	44,887
California	517,700	552,938	483,156	509,799	34,545	43,139
Oregon	12,942	0	NA	NA	12,942	0
Washington	8,320	1,753	56	5	8,264	1,748
Pacific Noncontiguous	**32,746**	**30,841**	**0**	**0**	32,746	30,841
Alaska	32,746	30,841	0	0	32,746	30,841
Hawaii	0	0	0	0	NA	NA
U.S. Total	**2,787,012**	**2,635,613**	**2,530,114**	**2,412,340**	256,898	223,273

* Value less than 0.5.
NA = Not applicable.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table 22. Coal and Petroleum Stocks by Census Division and State, as of December 31, 1989 and 1988

Census Division State	Coal (thousand short tons)		Petroleum[1] (thousand barrels)	
	1989	1988	1989	1988
New England	**1,058**	**1,110**	**5,521**	**5,424**
Connecticut	145	0	2,241	2,122
Maine	NA	NA	618	647
Massachusetts	642	737	2,228	2,167
New Hampshire	243	344	323	313
Rhode Island	28	28	74	135
Vermont	NA	NA	38	41
Middle Atlantic	**12,934**	**13,757**	**13,297**	**14,980**
New Jersey	632	528	2,510	2,848
New York	1,233	1,432	9,143	10,336
Pennsylvania	11,069	11,798	1,644	1,796
East North Central	**34,948**	**39,549**	**3,218**	**3,424**
Illinois	8,204	9,179	1,951	1,790
Indiana	8,043	9,997	178	165
Michigan	6,185	8,991	617	876
Ohio	6,607	7,218	283	377
Wisconsin	3,909	4,165	190	196
West North Central	**19,356**	**19,950**	**1,647**	**1,865**
Iowa	4,044	4,456	198	227
Kansas	3,266	3,300	601	668
Minnesota	2,052	2,579	130	135
Missouri	4,275	4,541	362	413
Nebraska	1,685	1,593	215	293
North Dakota	3,731	3,166	60	57
South Dakota	303	314	80	73
South Atlantic	**20,493**	**23,741**	**11,547**	**11,788**
Delaware	259	498	537	505
District of Columbia	NA	NA	93	121
Florida	4,383	4,804	6,457	6,562
Georgia	5,040	5,288	483	604
Maryland	1,046	1,476	1,290	1,374
North Carolina	2,795	3,727	206	227
South Carolina	1,873	1,661	470	430
Virginia	1,368	1,211	1,814	1,808
West Virginia	3,729	5,077	198	156
East South Central	**11,651**	**13,351**	**1,174**	**1,580**
Alabama	3,721	4,462	88	156
Kentucky	4,299	4,124	122	126
Mississippi	754	870	708	861
Tennessee	2,875	3,895	256	437
West South Central	**16,917**	**16,272**	**6,933**	**8,388**
Arkansas	2,134	1,899	251	247
Louisiana	2,627	2,772	1,209	1,351
Oklahoma	2,826	2,678	440	455
Texas	9,329	8,922	5,032	6,336
Mountain	**17,035**	**17,079**	**1,774**	**1,899**
Arizona	3,367	4,187	789	848
Colorado	3,921	3,763	255	283
Idaho	NA	NA	14	8
Montana	813	913	13	20
Nevada	993	1,434	482	460
New Mexico	1,403	1,392	155	210
Utah	3,202	2,772	35	34
Wyoming	3,337	2,619	31	36
Pacific Contiguous	**1,466**	**1,696**	**14,814**	**18,795**
California	NA	NA	14,470	18,401
Oregon	480	786	228	149
Washington	986	910	116	246
Pacific Noncontiguous	**3**	**3**	**1,344**	**1,141**
Alaska	3	3	236	243
Hawaii	NA	NA	1,109	899
U.S. Total	**135,860**	**146,507**	**61,270**	**69,285**

[1] Does not include petroleum coke. Petroleum coke stocks at the end of 1989 were 105 thousand short tons and in 1988 were 86 thousand short tons.

NA = Not applicable.

Note: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report."

Table 23. Fossil-Fuel Receipts by Census Division and State, 1989 and 1988

Census Division State	Coal (thousand short tons)		Petroleum[1] (thousand barrels)		Gas (million cubic feet)	
	1989	1988	1989	1988	1989	1988
New England	**6,326**	**6,377**	**58,939**	**60,107**	**48,076**	**14,978**
Connecticut	875	830	18,964	18,510	3,297	1,260
Maine	NA	NA	4,938	5,120	NA	NA
Massachusetts	4,387	4,285	29,220	29,931	42,540	13,552
New Hampshire	1,064	1,262	5,102	5,130	NA	NA
Rhode Island	NA	NA	715	1,416	2,239	166
Vermont	NA	NA	NA	NA	NA	NA
Middle Atlantic	**55,969**	**51,532**	**89,777**	**87,220**	**211,669**	**176,698**
New Jersey	3,324	2,477	12,276	13,664	39,338	34,051
New York	9,879	8,562	65,575	63,074	172,068	142,255
Pennsylvania	42,766	40,493	11,926	10,483	264	392
East North Central	**161,663**	**155,300**	**6,009**	**5,455**	**27,106**	**22,216**
Illinois	25,067	26,920	2,339	1,803	5,111	4,521
Indiana	40,560	36,414	405	324	3,863	3,074
Michigan	28,996	28,344	2,339	2,389	16,247	13,141
Ohio	49,505	46,008	821	823	590	478
Wisconsin	17,535	17,613	105	116	1,295	1,003
West North Central	**100,899**	**99,540**	**443**	**724**	**21,058**	**22,480**
Iowa	14,316	13,974	59	77	2,009	3,844
Kansas	14,725	14,798	72	133	14,254	12,923
Minnesota	16,176	15,451	21	16	1,964	3,370
Missouri	24,788	23,959	133	350	606	702
Nebraska	7,473	7,485	71	101	2,224	1,640
North Dakota	21,359	21,714	77	38	*	1
South Dakota	2,063	2,160	10	9	NA	NA
South Atlantic	**126,322**	**120,976**	**63,386**	**53,894**	**185,448**	**138,859**
Delaware	1,918	2,525	3,776	4,016	6,087	1,304
District of Columbia	NA	NA	1,297	959	NA	NA
Florida	23,375	23,770	40,432	39,073	155,902	129,897
Georgia	25,434	25,135	230	374	626	1,334
Maryland	8,494	8,854	10,649	5,635	17,307	3,874
North Carolina	18,413	16,795	203	229	NA	NA
South Carolina	9,805	9,002	83	112	1,881	1,664
Virginia	9,739	7,459	6,233	3,183	3,517	700
West Virginia	31,143	27,436	483	312	129	86
East South Central	**73,798**	**73,865**	**1,748**	**1,569**	**38,538**	**29,958**
Alabama	21,311	19,895	129	140	1,556	1,080
Kentucky	30,733	29,344	206	223	320	400
Mississippi	3,455	4,870	1,307	1,087	36,663	28,478
Tennessee	18,300	19,759	106	118	NA	NA
West South Central	**121,925**	**117,144**	**3,381**	**1,472**	**1,375,525**	**1,402,134**
Arkansas	11,502	11,907	235	240	29,473	21,976
Louisiana	11,594	12,078	578	510	212,443	237,906
Oklahoma	14,635	13,355	37	173	150,296	151,747
Texas	84,195	79,803	2,532	549	983,314	990,506
Mountain	**98,709**	**97,184**	**1,264**	**1,500**	**80,436**	**46,002**
Arizona	15,244	14,121	290	204	28,420	11,179
Colorado	15,752	14,949	34	13	4,754	5,205
Idaho	NA	NA	NA	NA	NA	NA
Montana	10,224	10,474	41	37	330	281
Nevada	7,067	7,886	664	986	20,859	9,150
New Mexico	15,238	14,522	65	97	25,986	20,002
Utah	13,385	12,256	40	34	NA	NA
Wyoming	21,798	22,976	131	128	87	185
Pacific Contiguous	**5,606**	**5,856**	**11,170**	**14,983**	**484,649**	**509,394**
California	NA	NA	11,104	14,966	484,649	509,394
Oregon	NA	235	12	NA	NA	NA
Washington	5,606	5,621	53	17	NA	NA
Pacific Noncontiguous	**NA**	**NA**	**10,306**	**10,000**	**NA**	**NA**
Alaska	NA	NA	NA	NA	NA	NA
Hawaii	NA	NA	10,306	10,000	NA	NA
U. S. Total	**753,217**	**727,775**	**246,422**	**236,923**	**2,472,506**	**2,362,721**

[1] Does not include petroleum coke. Petroleum coke receipts in 1989 were 495 thousand short tons and in 1988 were 356 thousand short tons.

* Value less than 0.5.

NA = Not applicable.

Notes: •Data are for plants with a fossil-fueled steam-electric nameplate capacity of 50 or more megawatts. •Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Table 24. Average Delivered Cost of Fossil-Fuel Receipts by Census Division and State, 1989 and 1988

Census Division State	Coal			Petroleum[1]			Gas		
	1989		1988	1989		1988	1989		1988
	($ per short ton)	(cents per 10^6 Btu)	(cents per 10^6 Btu)	($ per barrel)	(cents per 10^6 Btu)	(cents per 10^6 Btu)	($ per Mcf)	(cents per 10^6 Btu)	(cents per 10^6 Btu)
New England	**44.54**	**169.9**	**173.2**	**17.04**	**269.2**	**227.5**	**2.50**	**238.5**	**221.6**
Connecticut	56.88	213.7	228.6	18.01	285.6	239.7	2.59	251.1	217.4
Maine	NA	NA	NA	17.48	278.2	235.3	NA	NA	NA
Massachusetts	41.68	160.2	161.2	16.72	264.8	225.9	2.49	237.4	222.2
New Hampshire	46.18	172.8	177.7	14.85	226.9	186.9	NA	NA	NA
Rhode Island	NA	NA	NA	17.00	270.3	224.6	2.49	241.2	208.6
Vermont	NA	NA	NA	NA	NA	NA	NA	NA	NA
Middle Atlantic	**37.03**	**148.9**	**148.8**	**18.61**	**296.1**	**248.9**	**2.44**	**237.4**	**224.0**
New Jersey	46.84	175.8	171.7	18.93	303.5	251.2	2.54	245.5	224.5
New York	40.32	157.2	158.1	18.58	295.3	248.9	2.42	235.3	223.6
Pennsylvania	35.50	144.6	145.3	18.49	293.1	245.8	3.58	348.2	333.0
East North Central	**34.10**	**154.4**	**160.4**	**20.99**	**342.6**	**301.8**	**1.34**	**285.8**	**295.7**
Illinois	38.78	181.1	190.6	22.03	353.0	312.0	3.32	326.2	326.9
Indiana	29.08	135.9	143.2	24.27	421.8	363.4	2.70	269.5	259.1
Michigan	38.83	172.1	175.7	19.23	315.0	279.9	19	174.8	255.5
Ohio	35.21	148.7	152.2	21.06	345.8	311.7	3.15	313.2	346.5
Wisconsin	28.10	144.8	146.4	23.84	410.0	364.5	3.11	309.5	325.2
West North Central	**19.85**	**114.4**	**115.4**	**22.04**	**369.0**	**276.9**	**2.07**	**211.5**	**210.9**
Iowa	21.77	121.8	123.5	25.87	445.1	372.1	2.69	267.4	202.7
Kansas	22.00	123.9	123.9	25.24	432.8	318.6	1.92	197.6	206.0
Minnesota	21.01	119.8	119.6	25.50	441.6	369.2	2.16	214.6	198.4
Missouri	28.00	135.0	138.2	19.82	323.5	237.0	2.50	245.8	277.0
Nebraska	14.32	82.7	84.1	15.47	248.9	241.7	2.26	236.1	268.6
North Dakota	9.13	69.4	70.3	24.53	421.9	362.1	4.61	439.1	428.6
South Dakota	15.24	124.1	121.4	26.47	450.2	401.7	NA	NA	NA
South Atlantic	**R 41.19**	**R 165.8**	**166.5**	**17.47**	**277.4**	**227.7**	**2.52**	**248.0**	**212.2**
Delaware	46.41	179.3	180.6	17.54	277.4	232.1	2.73	254.4	242.1
District of Columbia	NA	NA	NA	20.78	345.6	278.9	NA	NA	NA
Florida	44.26	178.7	177.7	17.19	271.1	221.3	2.49	246.2	210.1
Georgia	R 42.96	R 177.5	174.7	24.95	426.7	283.8	3.23	315.6	273.4
Maryland	40.92	161.1	157.6	17.39	276.2	236.1	2.72	260.1	259.7
North Carolina	44.35	177.0	177.5	23.17	398.9	348.5	NA	NA	NA
South Carolina	43.08	170.7	176.0	24.71	426.3	373.6	2.27	222.1	180.6
Virginia	39.29	154.8	155.1	17.48	284.4	236.3	2.58	247.9	204.9
West Virginia	35.33	142.5	144.1	26.33	450.5	395.8	4.59	458.8	389.2
East South Central	**33.73**	**142.9**	**148.4**	**19.06**	**308.0**	**340.2**	**1.90**	**185.6**	**186.3**
Alabama	44.84	186.5	194.7	23.87	414.3	366.8	2.27	220.5	207.1
Kentucky	26.13	113.7	119.8	27.71	475.2	384.5	2.73	267.3	246.0
Mississippi	42.29	167.1	181.2	16.91	267.6	327.7	1.88	183.4	184.7
Tennessee	31.94	134.3	133.5	22.92	394.7	350.9	NA	NA	NA
West South Central	**22.69**	**147.5**	**149.5**	**22.54**	**375.0**	**345.5**	**2.24**	**215.7**	**207.8**
Arkansas	28.45	163.1	158.5	22.44	370.6	435.4	1.69	165.4	135.0
Louisiana	26.64	162.7	155.5	23.86	379.4	347.6	1.78	170.2	163.1
Oklahoma	24.03	136.1	148.2	23.92	415.0	268.2	3.05	292.5	281.3
Texas	21.12	144.9	147.2	22.22	373.8	329.1	2.23	215.3	209.0
Mountain	**21.80**	**111.6**	**109.5**	**20.79**	**342.6**	**289.4**	**2.24**	**217.2**	**229.4**
Arizona	28.81	136.0	140.5	23.92	403.1	407.0	2.32	224.4	224.1
Colorado	20.95	106.4	106.6	23.60	409.9	384.8	2.23	228.3	228.7
Idaho	NA	NA	NA	NA	NA	NA	NA	NA	NA
Montana	9.81	57.7	54.5	25.52	430.9	403.3	1.38	113.8	126.3
Nevada	33.80	152.0	136.3	17.85	286.5	244.8	2.17	211.3	271.8
New Mexico	22.61	123.8	117.5	22.17	378.3	308.0	2.20	213.3	213.6
Utah	28.05	123.9	126.5	26.18	445.2	398.4	NA	NA	NA
Wyoming	14.86	84.5	84.0	24.27	415.4	379.7	3.61	348.1	367.9
Pacific Contiguous	**25.40**	**155.6**	**154.5**	**18.93**	**307.9**	**266.0**	**3.04**	**292.4**	**283.1**
California	NA	NA	NA	18.91	307.6	265.8	3.04	292.4	283.1
Oregon	NA	NA	139.0	26.59	452.8	NA	NA	NA	NA
Washington	25.40	155.6	155.2	20.66	336.7	403.2	NA	NA	NA
Pacific Noncontiguous	**NA**	**NA**	**NA**	**20.55**	**329.1**	**286.7**	**NA**	**NA**	**NA**
Alaska	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hawaii	NA	NA	NA	20.55	329.1	286.7	NA	NA	NA
U. S. Total	**R 30.15**	**R 144.6**	**146.6**	**18.17**	**289.3**	**243.9**	**2.42**	**235.5**	**226.3**

[1] Does not include petroleum coke. Petroleum coke cost in 1989 was 85.7 cents per million Btu and in 1988 was 97.2 cents per million Btu.

Mcf = thousand cubic feet.

NA = Not applicable.

R = Revised data.

Notes: •Data are for plants with a fossil-fueled steam-electric nameplate capacity of 50 or more megawatts. •Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Retail Sales and Revenue

Electric power is an integral part of our way of life. It is indispensable to the factory, the commercial establishment, the home, and even most recreational facilities. The unavailability of electric power causes inconvenience to customers, loss of industrial production, and could even cause danger to individuals and social disorder. Consequently, the volume of electricity sales and the associated revenue from those sales play an important role in the U.S. economy. This chapter provides summary statistics on the sale of electricity to ultimate consumers, its associated revenue, and the average revenue per kilowatthour sold at the national, Census, and State levels.

Background

Because electricity itself cannot be stored, it must be generated, transmitted to the consumer, and consumed instantaneously. Electric companies were formed to provide these services. An electric system consists of energy conversion plants (stations) that convert different forms of energy to electric power; transformers to raise the voltage in order to reduce losses in transmitting the power; transmission lines to transmit the power to the general vicinity of consumption; transformers to lower the voltage; and distribution lines to distribute the power to the ultimate consumers. The entire system of generating stations, transformers, transmission lines, distribution lines, etc., is a power system. Power companies plan, design, build, and operate this power system. Some companies may only operate part of a power system. For example, many small power companies only distribute power to ultimate consumers, buying their power from other companies that generate power. Power systems are interconnected for mutual operating and economic advantages.

Electric utilities are high-investment businesses and historically have been treated as monopolies because duplicate facilities, particularly transmission and distribution lines, would be inefficient. Thus, franchises are granted to electric utilities for given geographical areas by regulatory officials. To obtain a franchise, electric utilities must provide service to all consumers in their territories at a reasonable cost.

The service territory of an electric utility is usually composed of many different combinations of consumers. Electric utilities classify their consumers by different factors such as demand, rate schedule, Standard Industrial Classification (SIC) code, distribution voltage, accounting methods, end-use applications, and other social and economic characteristics. Electric utilities use consumer classifications for planning purposes (load growth, peak demands) and for deriving their rate schedules, often with the approval of a government regulatory agency.

End-Use Sectors

Consumers within the service territory of an electric utility are generally grouped into end-use sectors -- residential, commercial, and industrial. The categorization of consumer is determined by the electric utility based on its service territory, size, location, ownership, and regulatory structure.

The residential sector includes electricity supplied to private households and apartment buildings, where energy is consumed primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking, and clothes drying.

The commercial sector may include electricity supplied to nonmanufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, and retail stores; and, health, social, and educational institutions. However, electric utilities may classify commercial service as that to all consumers whose demand or annual usage fall within a specified range. The range may be set by the electric utility based on its rate schedule.

The industrial sector includes electricity supplied to manufacturing, construction, mining, agriculture, fishing, and forestry establishments -- Standard Industrial Classification (SIC) codes 1-39. However, electric utilities may classify industrial service based on demand or annual usage exceeding a specified range. As in the commercial sector, the range may be set by the electric utility based on its rate schedule.

Other sales include public street and highway lighting, railroads and railways, municipalities, divisions or agencies of State and Federal governments under special contracts or agreements, and other utility departments as defined by the pertinent regulatory agency and/or electric utility.

Revenue Requirements

The revenue requirements of an electric utility are set to reimburse the utility for providing electric service. The revenue requirement is the anticipated cost of providing services for some period of time in the future, usually a year. Revenue requirements are based on operating expenses, depreciation expense, taxes, and return on the ratebase (profit of the electric utility). The process of determining electricity prices generally follows three stages: 1) identification of revenue requirements; 2) allocation of the requirements for different classes of service (sectors); and, 3) establishment of rate schedules for each sector.

The rate schedules developed to generate revenue requirements for electric utilities are unique to each utility. The authority for the approval of these rates is based on the ownership class applicable to the utility. For example, investor-owned electric utilities are regulated by State public service commissions and the Federal Energy Regulatory Commission. Public electric utilities, in most States, are controlled through locally elected or appointed officials. A more detailed discussion on utility classes of ownership is contained in the "Industry Profile" section in the first chapter of this publication.

A rate schedule is a statement that the utility will provide service to a particular class of consumer at a certain price. Prices between sectors vary based on various objectives of the utility. These objectives include the need to allocate the various costs incurred in providing service, to maintain the existing consumer base of the utility, and to promote new business.

Average Revenue per Kilowatthour

Average revenue per unit (kilowatthour) of electricity sold is calculated by dividing total annual revenue by total annual retail sales for each sector and State. Average revenue per kilowatthour from residential consumers are generally higher than for any other sector due in part to the higher costs associated with serving many consumers who use relatively small amounts of electricity. These costs include direct-load costs (such as those for distribution lines, transformers, and meters) in addition to consumer or administrative costs. The industrial sector, which generally covers consumers with the highest use of electricity, has the lowest average revenue per kilowatthour because of the economies of serving a few consumers who use relatively large amounts of electricity.

Because of the type and availability of capacity, and the cost of fuel, average revenue of electricity sold differ across U. S. Census divisions. The New England and Middle Atlantic Census Divisions tend to have average revenue per kilowatthour that is higher than the average in the United States because of their higher cost of fuel (petroleum), and their higher labor costs whereas the East North Central and South Atlantic Census Divisions had lower average revenue per kilowatthour because of their reliance on less expensive coal-fired generation. Petroleum is generally a more expensive energy source than coal. Because the Mountain and Pacific Contiguous Census Divisions rely on less expensive hydroelectric generation, average revenue per kilowatthour in these regions is usually below the national average for all divisions. The Census divisions where Federal hydroelectric facilities provide electricity also tend to have lower average revenue per kilowatthour.

Data Sources

Summary statistics on retail sales of electricity and average revenue are provided in the following tables. These data were obtained from the Form EIA-861, "Annual Electric Utility Report." The Form EIA-861 is used to collect annual data from all electric utilities (approximately 3,250), that own and/or operate facilities within the United States, its territories, and Puerto Rico, for the generation, transmission, distribution, or sale of electric energy primarily for use by the public. More detailed statistics are published in the *Electric Sales, Revenue and Bills*.[24]

Form EIA-861 figures shown in this publication differ somewhat from the sum of the monthly Form EIA-826 figures for sales published in the *Electric Power Monthly*. The statistics from the Form EIA-826 are monthly estimates collected from a sample of electric utilities. Both forms use sectoral classifications (residential, commercial, and industrial) based on the usual classification of consumers by the utilities. The sectoral classification scheme for electricity sales can vary from utility to utility, as influenced by the local public utility commission. At the national level, the Form EIA-861 and Form EIA-826 figures correspond closely (within 3 percent) for all end-use sectors. Some larger differences occur at the State level particularly for Tennessee due to a misclassification of commercial and industrial data in the Form EIA-826 survey.

[24]Data for 1988: Energy Information Administration, *Electric Sales, Revenue, and Bills*, DOE/EIA-0540(88)(Washington, DC, March 1990); data for 1989 will be published in the *Electric Sales and Revenue, DOE/EIA-0540(89)(Washington, DC)*.

Table 25. Sales to Ultimate Consumers and Associated Revenue by Sector, 1985-1989

Item	1989[1]	1988	1987	1986	1985
Sales (million kilowatthours)[2]					
Residential	905,525	892,866	850,410	819,088	793,934
Commercial	725,861	699,100	660,433	630,520	605,989
Industrial	925,659	896,498	858,233	830,531	836,772
Other[3]	89,765	89,598	88,196	88,615	87,279
U.S. Total	**2,646,809**	**2,578,062**	**2,457,272**	**2,368,753**	**2,323,974**
Revenue (million dollars)					
Residential	69,240	66,790	63,318	60,773	58,710
Commercial	52,228	49,224	46,787	45,386	44,082
Industrial	43,719	42,145	40,949	40,982	41,580
Other[3]	5,609	5,551	5,479	5,412	5,312
U.S. Total	**170,797**	**163,710**	**156,532**	**152,553**	**149,684**

[1] Data for 1989 are preliminary.
[2] The Form EIA-861 data shown in this publication differ somewhat from Form EIA-826, "Monthly Electric Sales and Revenue Report with State Distributions," data published in the *Electric Power Monthly* and issues of this publication prior to 1988. See Appendix C for a detailed description of these differences.
[3] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 26. Average Revenue per Kilowatthour by Sector, 1985-1989
(Cents)

Sector	1989[1]	1988	1987	1986	1985
Residential	7.6	7.5	7.4	7.4	7.4
Commercial	7.2	7.0	7.1	7.2	7.3
Industrial	4.7	4.7	4.8	4.9	5.0
Other[2]	6.2	6.2	6.2	6.1	6.1
U.S. Average	**6.5**	**6.4**	**6.4**	**6.4**	**6.4**

[1] Data for 1989 are preliminary.
[2] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
Notes: •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales. •Totals may not equal sum of components because of independent rounding. •The Form EIA-861 data shown in this publication differ somewhat from Form EIA-826, "Monthly Electric Sales and Revenue Report with State Distributions," data published in the *Electric Power Monthly* and issues of this publication prior to 1988. See Appendix C for a detailed description of these differences.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 27. Sales to Ultimate Consumers by Sector, Census Division, and State, 1989 and 1988

(Million Kilowatthours)

Census Division State	Total		Residential		Commercial		Industrial		Other[1]	
	1989[2]	1988	1989[2]	1988	1989[2]	1988	1989[2]	1988	1989[2]	1988
New England	**104,500**	**102,398**	**37,843**	**37,069**	**37,287**	**36,169**	**27,367**	**27,209**	**2,003**	**1,949**
Connecticut	27,365	26,923	10,485	10,300	10,277	9,961	6,235	6,305	367	356
Maine	11,434	11,264	4,009	3,904	2,647	2,569	4,599	4,616	179	175
Massachusetts	45,683	44,727	15,772	15,511	18,417	17,886	10,381	10,243	1,113	1,087
New Hampshire	9,086	8,848	3,542	3,464	2,020	1,947	3,420	3,339	103	99
Rhode Island	6,359	6,220	2,370	2,319	2,439	2,354	1,360	1,361	190	186
Vermont	4,573	4,416	1,664	1,572	1,486	1,453	1,373	1,345	50	46
Middle Atlantic	**305,462**	**300,646**	**96,714**	**95,945**	**101,966**	**99,075**	**93,078**	**92,290**	**13,704**	**13,337**
New Jersey	63,359	62,112	20,695	20,656	26,472	25,143	15,713	15,844	478	469
New York	128,203	125,643	37,878	37,460	47,117	46,598	31,448	30,155	11,760	11,430
Pennsylvania	113,900	112,891	38,141	37,828	28,377	27,334	45,916	46,291	1,466	1,438
East North Central	**455,122**	**446,415**	**135,030**	**136,879**	**108,764**	**106,280**	**196,667**	**188,530**	**14,661**	**14,726**
Illinois	109,301	110,041	32,378	33,980	30,943	30,551	33,481	37,942	7,498	7,568
Indiana	72,891	71,675	22,281	22,486	15,216	15,058	34,747	33,474	647	657
Michigan	82,929	82,517	25,319	25,316	20,200	19,530	36,131	36,324	1,279	1,346
Ohio	141,624	134,316	38,792	38,713	30,019	29,004	68,314	62,238	4,499	4,360
Wisconsin	48,376	47,866	16,259	16,383	12,385	12,137	18,995	18,552	738	794
West North Central	**184,036**	**[R] 183,241**	**67,834**	**[R] 68,918**	**48,742**	**[R] 48,113**	**62,302**	**[R] 61,155**	**5,158**	**5,055**
Iowa	28,712	28,838	10,394	10,677	6,474	6,320	11,017	11,025	827	816
Kansas	25,822	25,829	8,898	9,121	8,747	8,583	7,797	7,708	380	417
Minnesota	45,932	45,728	14,778	14,996	7,707	7,792	22,700	22,131	748	808
Missouri	52,603	[R] 52,247	21,057	[R] 21,348	17,916	[R] 17,541	12,792	[R] 12,556	838	802
Nebraska	17,567	17,259	6,723	6,813	5,030	4,996	4,370	4,104	1,443	1,346
North Dakota	7,062	7,107	3,060	3,050	1,504	1,521	2,013	2,070	484	466
South Dakota	6,338	6,235	2,923	2,913	1,364	1,359	1,612	1,562	438	400
South Atlantic	**520,886**	**499,926**	**206,796**	**199,187**	**146,327**	**139,545**	**151,018**	**145,387**	**16,744**	**15,806**
Delaware	8,065	7,543	2,623	2,533	2,233	2,109	3,160	2,854	49	47
District of Columbia	9,653	9,380	1,466	1,465	4,945	4,793	2,930	2,809	312	312
Florida	138,474	130,241	68,184	63,972	48,943	45,892	17,040	16,356	4,307	4,021
Georgia	77,060	74,346	28,349	27,609	21,431	19,850	26,388	25,984	891	903
Maryland	49,259	47,564	19,069	18,483	10,081	11,006	19,456	17,446	652	628
North Carolina	88,209	85,540	32,784	32,212	22,506	21,513	31,152	30,211	1,768	1,604
South Carolina	53,857	52,809	17,464	17,172	11,343	10,790	24,301	24,113	749	734
Virginia	73,461	70,115	29,223	28,192	19,920	18,768	16,395	15,690	7,922	7,465
West Virginia	22,847	22,388	7,634	7,549	4,926	4,823	10,195	9,925	93	91
East South Central	**221,362**	**211,567**	**76,636**	**75,826**	**37,262**	**33,457**	**102,882**	**97,750**	**4,582**	**4,634**
Alabama	58,187	56,638	19,842	19,641	10,517	9,588	27,232	26,758	596	651
Kentucky	58,487	54,078	16,922	16,811	8,952	8,439	30,173	26,446	2,440	2,382
Mississippi	29,574	28,080	11,516	11,415	6,495	5,928	10,958	10,115	605	622
Tennessee	75,113	72,872	28,355	27,960	11,297	9,502	34,520	34,431	940	980
West South Central	**354,594**	**346,955**	**124,174**	**121,809**	**90,343**	**88,168**	**127,978**	**124,788**	**12,099**	**12,189**
Arkansas	26,085	25,273	9,957	9,946	5,982	5,783	9,562	8,931	584	613
Louisiana	61,842	60,011	20,515	20,134	13,437	13,088	24,762	23,559	3,128	3,230
Oklahoma	37,007	37,326	14,083	14,475	9,944	10,100	11,039	10,719	1,941	2,032
Texas	229,660	224,346	79,620	77,255	60,979	59,197	82,615	81,579	6,446	6,315
Mountain	**156,305**	**150,269**	**48,527**	**47,309**	**47,999**	**46,269**	**52,461**	**49,820**	**7,318**	**6,870**
Arizona	40,748	38,916	15,247	14,731	13,037	12,346	9,722	9,261	2,741	2,578
Colorado	30,139	29,335	9,595	9,551	13,157	12,683	6,427	6,295	959	806
Idaho	17,821	17,165	5,713	5,449	4,667	4,562	7,143	6,807	297	346
Montana	13,061	12,942	3,456	3,301	2,670	2,620	6,535	6,438	400	582
Nevada	14,968	13,684	5,169	4,968	3,672	3,489	5,504	4,685	624	543
New Mexico	13,370	12,755	3,463	3,394	4,385	4,264	4,208	4,032	1,314	1,065
Utah	14,965	14,507	4,163	4,151	4,343	4,244	5,629	5,321	830	791
Wyoming	11,234	10,964	1,721	1,764	2,068	2,062	7,293	6,980	151	158
Pacific	**332,432**	**324,782**	**108,085**	**106,181**	**103,178**	**98,233**	**107,878**	**105,531**	**13,291**	**14,838**
California	204,139	200,637	64,347	64,639	75,282	70,706	55,596	54,988	8,913	10,304
Oregon	41,619	39,312	15,085	14,338	10,942	10,605	14,913	13,633	679	736
Washington	86,674	84,832	28,653	27,203	16,953	16,922	37,369	36,909	3,699	3,798
Pacific Noncontiguous	**12,112**	**[R] 11,764**	**3,886**	**[R] 3,742**	**3,995**	**[R] 3,792**	**4,027**	**[R] 4,037**	**205**	**194**
Alaska	4,142	[R] 4,045	1,643	[R] 1,590	1,897	[R] 1,778	450	[R] 542	151	136
Hawaii	7,970	7,719	2,242	2,151	2,098	2,014	3,576	3,495	54	58
U. S. Total	**2,646,809**	**2,578,062**	**905,525**	**892,866**	**725,861**	**699,100**	**925,659**	**896,498**	**89,765**	**89,598**

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

[2] Data for 1989 are preliminary.

R = Revised data.

Notes: •Totals may not equal sum of components because of independent rounding. •The Form EIA-861 data shown in this publication differ somewhat from Form EIA-826, "Monthly Electric Sales and Revenue Report with State Distributions," data published in the *Electric Power Monthly* and issues of this publication prior to 1988. See Appendix C for a detailed description of these differences.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 28. Number of Ultimate Consumers by Sector, Census Division, and State, 1989 and 1988
(Thousands)

Census Division State	Total		Residential		Commercial		Industrial		Other[1]	
	1989[2]	1988	1989[2]	1988	1989[2]	1988	1989[2]	1988	1989[2]	1988
New England	**5,966**	**5,843**	**5,272**	**5,172**	**622**	**600**	**27**	**26**	**45**	**46**
Connecticut	1,427	1,406	1,295	1,277	123	119	5	5	5	4
Maine	647	631	560	547	66	63	3	3	18	18
Massachusetts	2,615	2,558	2,303	2,256	285	275	14	13	13	14
New Hampshire	558	543	481	470	70	67	2	2	5	5
Rhode Island	429	421	382	375	44	42	3	3	1	2
Vermont	289	283	251	246	35	33	1	1	3	3
Middle Atlantic	**15,473**	**15,269**	**13,668**	**13,507**	**1,706**	**1,665**	**52**	**51**	**46**	**45**
New Jersey	3,272	3,223	2,872	2,834	379	369	12	12	9	8
New York	7,058	6,974	6,209	6,145	809	790	11	10	29	29
Pennsylvania	5,143	5,072	4,587	4,529	518	506	30	29	8	8
East North Central	**18,129**	**17,900**	**16,258**	**16,065**	**1,723**	**1,690**	**71**	**69**	**78**	**76**
Illinois	4,776	4,725	4,317	4,273	435	428	4	4	19	19
Indiana	2,428	2,392	2,165	2,134	237	234	15	14	11	11
Michigan	4,037	3,980	3,626	3,582	378	368	14	15	19	16
Ohio	4,660	4,603	4,164	4,117	447	437	31	31	18	18
Wisconsin	2,229	2,199	1,987	1,959	226	223	6	6	10	12
West North Central	**8,278**	**R 8,191**	**7,182**	**R 7,107**	**939**	**926**	**46**	**50**	**112**	**108**
Iowa	1,301	1,293	1,130	1,122	156	154	4	4	12	12
Kansas	1,184	1,171	1,007	994	153	148	13	18	12	11
Minnesota	1,958	1,936	1,732	1,712	194	193	9	8	23	23
Missouri	2,395	R 2,360	2,120	R 2,090	250	245	10	10	15	14
Nebraska	795	786	651	646	102	101	5	4	37	34
North Dakota	314	317	263	265	44	44	3	3	4	5
South Dakota	331	328	279	277	40	40	2	2	9	8
South Atlantic	**19,972**	**19,476**	**17,588**	**17,132**	**2,116**	**2,078**	**90**	**86**	**179**	**179**
Delaware	307	297	276	267	30	28	1	1	1	1
District of Columbia	216	214	189	187	26	26	*	*	*	*
Florida	6,467	6,282	5,680	5,483	688	699	25	26	74	74
Georgia	2,910	2,838	2,584	2,528	288	274	19	20	19	17
Maryland	1,885	1,837	1,696	1,656	177	175	11	6	1	1
North Carolina	3,165	3,103	2,748	2,694	375	362	15	15	28	33
South Carolina	1,609	1,572	1,394	1,364	194	187	4	4	17	17
Virginia	2,562	2,489	2,276	2,215	244	235	5	5	36	35
West Virginia	851	844	744	739	94	92	10	10	3	3
East South Central	**6,950**	**6,811**	**6,056**	**5,979**	**774**	**739**	**40**	**43**	**80**	**50**
Alabama	1,876	1,840	1,639	1,616	217	207	9	10	11	7
Kentucky	1,667	1,638	1,468	1,445	174	169	8	9	17	16
Mississippi	1,135	1,115	980	971	135	130	6	6	14	8
Tennessee	2,272	2,218	1,969	1,947	248	234	17	18	38	19
West South Central	**11,936**	**11,879**	**10,348**	**10,238**	**1,348**	**1,345**	**111**	**147**	**129**	**149**
Arkansas	1,127	1,109	978	963	110	108	22	21	18	18
Louisiana	1,836	1,832	1,616	1,613	188	188	14	15	17	17
Oklahoma	1,555	1,559	1,339	1,345	186	187	15	15	14	13
Texas	7,418	7,379	6,414	6,318	863	862	61	96	80	102
Mountain	**6,093**	**5,977**	**5,267**	**5,162**	**726**	**718**	**29**	**28**	**71**	**69**
Arizona	1,574	1,534	1,390	1,354	158	154	4	4	22	21
Colorado	1,595	1,572	1,378	1,363	196	192	2	3	19	14
Idaho	469	464	394	390	68	67	4	4	3	3
Montana	408	412	340	339	56	57	3	3	10	13
Nevada	524	489	454	423	68	63	1	1	2	2
New Mexico	661	647	564	551	84	84	5	4	8	8
Utah	623	614	554	547	58	57	7	7	4	4
Wyoming	239	244	193	194	38	43	3	3	4	4
Pacific Contiguous	**15,252**	**14,906**	**13,336**	**13,008**	**1,787**	**1,769**	**54**	**47**	**74**	**83**
California	11,736	11,435	10,250	9,986	1,405	1,364	38	38	43	47
Oregon	1,323	1,323	1,146	1,129	161	181	6	3	10	11
Washington	2,193	2,148	1,941	1,892	221	224	10	6	22	25
Pacific Noncontiguous	**587**	**R 576**	**503**	**R 493**	**78**	**76**	**1**	**1**	**6**	**5**
Alaska	229	R 226	193	R 191	31	30	1	1	4	4
Hawaii	359	351	309	303	47	46	1	1	2	1
U. S. Average	**108,635**	**106,827**	**95,476**	**93,863**	**11,818**	**11,606**	**522**	**548**	**819**	**811**

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
[2] Data for 1989 are preliminary.
* Value less than 0.5 thousand.
R = Revised data.
Notes: •Totals may not equal sum of components because of independent rounding. •The number of ultimate consumers is an average of the number of consumers at the close of each month.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 29. Revenue from Sales to Ultimate Consumers by Sector, Census Division, and State, 1989 and 1988

(Million Dollars)

Census Division State	Total		Residential		Commercial		Industrial		Other[1]	
	1989[2]	1988	1989[2]	1988	1989[2]	1988	1989[2]	1988	1989[2]	1988
New England	**8,649**	**8,082**	**3,484**	**3,260**	**3,076**	**2,849**	**1,877**	**1,777**	**213**	**197**
Connecticut	2,398	2,255	1,005	950	898	828	449	434	46	43
Maine	801	755	341	322	195	182	247	234	18	16
Massachusetts	3,801	3,489	1,437	1,317	1,490	1,369	758	697	116	106
New Hampshire	759	732	338	328	177	168	231	224	13	12
Rhode Island	526	494	213	200	196	181	102	98	15	15
Vermont	365	358	149	143	121	120	90	89	6	5
Middle Atlantic	**25,402**	**24,064**	**9,620**	**9,225**	**9,215**	**8,669**	**5,432**	**5,117**	**1,135**	**1,052**
New Jersey	5,604	5,286	2,085	2,023	2,317	2,116	1,126	1,072	77	75
New York	11,385	10,736	4,140	3,920	4,671	4,492	1,665	1,489	909	834
Pennsylvania	8,413	8,042	3,395	3,283	2,227	2,061	2,641	2,556	149	143
East North Central	**28,511**	**27,872**	**10,788**	**10,817**	**7,819**	**7,486**	**8,917**	**8,620**	**988**	**949**
Illinois	8,210	8,048	3,227	3,309	2,407	2,295	2,068	1,960	507	483
Indiana	3,949	4,031	1,544	1,607	932	951	1,420	1,420	52	53
Michigan	5,621	5,450	1,915	1,873	1,588	1,491	2,007	1,975	112	110
Ohio	8,099	7,715	3,017	2,938	2,163	2,020	2,649	2,504	270	253
Wisconsin	2,632	2,629	1,085	1,091	729	728	772	760	47	50
West North Central	**10,938**	**R 10,952**	**4,809**	**R 4,891**	**3,078**	**R 3,031**	**2,745**	**R 2,723**	**306**	**305**
Iowa	1,695	1,731	787	810	414	415	444	457	50	49
Kansas	1,657	1,691	682	714	569	560	377	386	28	31
Minnesota	2,433	2,457	994	1,014	460	463	931	930	48	51
Missouri	3,396	R 3,376	1,545	R 1,565	1,160	1,136	633	619	58	57
Nebraska	972	915	414	405	287	271	184	158	87	80
North Dakota	403	409	188	190	97	99	100	102	18	19
South Dakota	383	373	199	195	91	88	76	72	17	18
South Atlantic	**32,551**	**30,950**	**15,177**	**14,420**	**9,502**	**9,031**	**6,867**	**6,528**	**1,005**	**971**
Delaware	507	502	214	213	149	147	139	138	5	4
District of Columbia	567	576	88	92	311	317	150	149	18	18
Florida	9,660	9,197	5,273	5,001	3,236	3,091	863	833	289	272
Georgia	4,909	4,632	2,049	1,939	1,556	1,414	1,235	1,213	69	66
Maryland	2,946	2,780	1,308	1,241	668	716	918	772	52	50
North Carolina	5,508	5,255	2,511	2,406	1,413	1,344	1,470	1,402	114	103
South Carolina	3,039	2,955	1,256	1,224	704	669	1,035	1,022	43	40
Virginia	4,322	3,978	2,027	1,856	1,196	1,071	690	640	408	410
West Virginia	1,091	1,075	451	448	267	262	366	358	8	7
East South Central	**11,959**	**11,670**	**4,656**	**4,572**	**2,342**	**2,088**	**4,704**	**4,738**	**256**	**272**
Alabama	3,233	3,134	1,307	1,277	712	637	1,182	1,183	33	37
Kentucky	2,824	2,779	953	952	476	453	1,283	1,263	112	112
Mississippi	1,829	1,735	786	746	466	422	530	512	47	55
Tennessee	4,072	4,023	1,611	1,597	689	577	1,709	1,780	64	68
West South Central	**20,469**	**19,762**	**8,796**	**8,481**	**5,626**	**5,415**	**5,[illegible]96**	**5,114**	**751**	**752**
Arkansas	1,681	1,606	774	757	401	376	468	431	39	41
Louisiana	3,689	3,509	1,505	1,435	940	888	1,053	985	190	201
Oklahoma	2,049	2,058	962	975	582	586	404	393	102	104
Texas	13,050	12,588	5,556	5,314	3,703	3,564	3,372	3,305	420	406
Mountain	**9,169**	**8,847**	**3,501**	**3,420**	**3,123**	**3,001**	**2,182**	**2,068**	**383**	**358**
Arizona	3,059	2,887	1,349	1,289	1,057	995	524	487	130	115
Colorado	1,791	1,731	673	662	760	722	292	284	67	62
Idaho	674	635	275	258	199	188	187	175	14	14
Montana	531	531	186	179	123	124	204	205	18	23
Nevada	788	740	296	298	221	210	244	208	26	23
New Mexico	976	940	312	306	361	351	223	214	80	69
Utah	867	907	308	324	294	298	226	241	39	44
Wyoming	483	477	104	103	108	111	261	254	9	9
Pacific Contiguous	**22,123**	**20,560**	**8,040**	**7,361**	**8,088**	**7,325**	**5,447**	**5,204**	**548**	**671**
California	17,309	15,967	6,080	5,518	6,867	6,142	3,963	3,780	400	527
Oregon	1,774	1,693	719	686	529	515	493	457	33	34
Washington	3,040	2,901	1,241	1,156	692	668	991	967	116	110
Pacific Noncontiguous	**1,024**	**R 951**	**369**	**R 344**	**359**	**R 327**	**272**	**R 257**	**24**	**23**
Alaska	382	R 364	161	R 154	166	R 151	35	R 40	20	18
Hawaii	642	588	208	190	193	176	237	217	5	5
U. S. Total	**170,797**	**163,710**	**69,240**	**66,790**	**52,228**	**49,224**	**43,719**	**42,145**	**5,609**	**5,551**

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

[2] Data for 1989 are preliminary.

R = Revised data.

Note: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 30. Average Revenue per Kilowatthour by Sector, Census Division, and State, 1989 and 1988

(Cents)

Census Division State	Total		Residential		Commercial		Industrial		Other[1]	
	1989[2]	1988	1989[2]	1988	1989[2]	1988	1989[2]	1988	1989[2]	1988
New England	**8.3**	**7.9**	**9.2**	**8.8**	**8.2**	**7.9**	**6.9**	**6.5**	**10.6**	**10.1**
Connecticut	8.8	8.4	9.6	9.2	8.7	8.3	7.2	6.9	12.4	12.0
Maine	7.0	6.7	8.5	8.3	7.4	7.1	5.4	5.1	10.0	9.4
Massachusetts	8.3	7.8	9.1	8.5	8.1	7.7	7.3	6.8	10.4	9.7
New Hampshire	8.4	8.3	9.5	9.5	8.8	8.6	6.7	6.7	12.9	11.8
Rhode Island	8.3	7.9	9.0	8.6	8.0	7.7	7.5	7.2	7.8	8.2
Vermont	8.0	8.1	8.9	9.1	8.1	8.3	6.5	6.6	11.3	10.7
Middle Atlantic	**8.3**	**8.0**	**9.9**	**9.6**	**9.0**	**8.8**	**5.8**	**5.5**	**8.3**	**7.9**
New Jersey	8.8	8.5	10.1	9.8	8.8	8.4	7.2	6.8	16.2	16.1
New York	8.9	8.5	10.9	10.5	9.9	9.6	5.3	4.9	7.7	7.3
Pennsylvania	7.4	7.1	8.9	8.7	7.8	7.5	5.8	5.5	10.2	9.9
East North Central	**6.3**	**6.2**	**8.0**	**7.9**	**7.2**	**7.0**	**4.5**	**4.6**	**6.7**	**6.4**
Illinois	7.5	7.3	10.0	9.7	7.8	7.5	5.4	5.2	6.8	6.4
Indiana	5.4	5.6	6.9	7.1	6.1	6.3	4.1	4.2	8.0	8.1
Michigan	6.8	6.6	7.6	7.4	7.9	7.6	5.6	5.4	8.7	8.2
Ohio	5.7	5.7	7.8	7.6	7.2	7.0	3.9	4.0	6.0	5.8
Wisconsin	5.4	5.5	6.7	6.7	5.9	6.0	4.1	4.1	6.3	6.2
West North Central	**5.9**	**6.0**	**7.1**	**7.1**	**6.3**	**6.3**	**4.4**	**4.5**	**5.9**	**6.0**
Iowa	5.9	6.0	7.6	7.6	6.4	6.6	4.0	4.1	6.1	6.1
Kansas	6.4	6.5	7.7	7.8	6.5	6.5	4.8	5.0	7.5	7.4
Minnesota	5.3	5.4	6.7	6.8	6.0	5.9	4.1	4.2	6.4	6.3
Missouri	6.5	6.5	7.3	7.3	6.5	6.5	4.9	4.9	6.9	7.1
Nebraska	5.5	5.3	6.2	5.9	5.7	5.4	4.2	3.9	6.0	5.0
North Dakota	5.7	5.8	6.1	6.2	6.5	6.5	4.9	4.9	3.8	4.0
South Dakota	6.0	6.0	6.8	6.7	6.7	6.5	4.7	4.6	3.8	4.5
South Atlantic	**6.2**	**6.2**	**7.3**	**7.2**	**6.5**	**6.5**	**4.5**	**4.5**	**6.0**	**6.1**
Delaware	6.3	6.7	8.2	8.4	6.7	7.0	4.4	4.8	9.3	9.2
District of Columbia	5.9	6.1	6.0	6.3	6.3	6.6	5.1	5.3	5.7	5.6
Florida	7.0	7.1	7.7	7.8	6.6	6.7	5.1	5.1	6.7	6.8
Georgia	6.4	6.2	7.2	7.0	7.3	7.1	4.7	4.7	7.8	7.3
Maryland	6.0	5.8	6.9	6.7	6.6	6.5	4.7	4.4	7.9	7.9
North Carolina	6.2	6.1	7.7	7.5	6.3	6.2	4.7	4.6	6.4	6.4
South Carolina	5.6	5.6	7.2	7.1	6.2	6.2	4.3	4.2	5.8	5.5
Virginia	5.9	5.7	6.9	6.6	6.0	5.7	4.2	4.1	5.2	5.5
West Virginia	4.8	4.8	5.9	5.9	5.4	5.4	3.6	3.6	8.3	8.2
East South Central	**5.4**	**5.5**	**6.1**	**6.0**	**6.3**	**6.2**	**4.6**	**4.8**	**5.6**	**5.9**
Alabama	5.6	5.5	6.6	6.5	6.8	6.6	4.3	4.4	5.6	5.6
Kentucky	4.8	5.1	5.6	5.7	5.3	5.4	4.3	4.8	4.6	4.7
Mississippi	6.2	6.2	6.8	6.5	7.2	7.1	4.8	5.1	7.7	8.8
Tennessee	5.4	5.5	5.7	5.7	6.1	6.1	5.0	5.2	6.8	7.0
West South Central	**5.8**	**5.7**	**7.1**	**7.0**	**6.2**	**6.1**	**4.1**	**4.1**	**6.2**	**6.2**
Arkansas	6.4	6.4	7.8	7.6	6.7	6.5	4.9	4.8	6.7	6.7
Louisiana	6.0	5.8	7.3	7.1	7.0	6.8	4.3	4.2	6.1	6.2
Oklahoma	5.5	5.5	6.8	6.7	5.9	5.8	3.7	3.7	5.2	5.1
Texas	5.7	5.6	7.0	6.9	6.1	6.0	4.1	4.1	6.5	6.4
Mountain	**5.9**	**5.9**	**7.2**	**7.2**	**6.5**	**6.5**	**4.1**	**4.2**	**5.2**	**5.2**
Arizona	7.5	7.4	8.8	8.8	8.1	8.1	5.4	5.3	4.7	4.5
Colorado	5.9	5.9	7.0	6.9	5.8	5.7	4.5	4.5	7.0	7.7
Idaho	3.8	3.7	4.8	4.7	4.3	4.1	2.6	2.6	4.6	3.9
Montana	4.1	4.1	5.4	5.4	4.6	4.8	3.1	3.2	4.5	3.9
Nevada	5.3	5.4	5.7	6.0	6.0	6.0	4.4	4.4	4.2	4.2
New Mexico	7.3	7.4	9.0	9.0	8.2	8.2	5.3	5.3	6.1	6.1
Utah	5.8	6.2	7.4	7.8	6.8	7.0	4.0	4.5	4.6	5.5
Wyoming	4.3	4.4	6.0	5.8	5.2	5.4	3.6	3.6	6.0	5.6
Pacific Contiguous	**6.7**	**6.3**	**7.4**	**6.9**	**7.8**	**7.5**	**5.0**	**4.9**	**4.1**	**4.5**
California	8.5	8.0	9.4	8.5	9.1	8.7	7.1	6.9	4.5	5.1
Oregon	4.3	4.3	4.8	4.8	4.8	4.9	3.3	3.4	4.8	4.6
Washington	3.5	3.4	4.3	4.2	4.1	3.9	2.7	2.6	3.1	2.9
Pacific Noncontiguous	**8.5**	**8.1**	**9.5**	**R 9.2**	**9.0**	**8.6**	**6.7**	**6.4**	**11.9**	**11.9**
Alaska	9.2	R 9.0	9.8	R 9.7	8.8	8.5	7.7	7.5	13.1	13.6
Hawaii	8.1	7.6	9.3	8.8	9.2	8.8	6.6	6.2	8.5	8.0
U. S. Average	**6.5**	**6.4**	**7.6**	**7.5**	**7.2**	**7.0**	**4.7**	**4.7**	**6.2**	**6.2**

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales. The average revenue for other sales may include ownership, operation, maintenance, and rental fees for equipment and/or demand and service charges.

[2] Data for 1989 are preliminary.

R = Revised data.

Notes: •The average revenue per kilowatthour of electricity sold is calculated by dividing revenue by sales. •Totals may not equal sum of components because of independent rounding. •The Form EIA-861 data shown in this publication differ somewhat from Form EIA-826, "Monthly Electric Sales and Revenue Report with State Distributions," data published in the *Electric Power Monthly* and issues of this publication prior to 1988. See Appendix C for a detailed description of these differences.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Financial Statistics

This chapter presents data on the financial results of operations for selected investor-owned and publicly owned electric utilities. Composite financial data on other segments of the electric utility industry, for example, Federal electric utilities and rural electric cooperatives, are not included in this discussion.[25] The statistical data exhibited consist of the Composite Statement of Income, the Composite Balance Sheet, Financial Indicators, and Revenue and Expense Statistics. Historical data are provided for a 3-year period on the investor-owned electric utilities and for 1 year on the publicly owned electric utilities.

Background

Today, virtually all investor-owned electric utilities are subject to State and Federal regulatory jurisdiction. State commissions have the authority to regulate electric rates of companies engaged in providing service to ultimate consumers (retail sales of electricity) and to oversee the issuance of mortgage bonds, debentures, notes, preferred stocks, and common stock. The Federal Energy Regulatory Commission (FERC) regulates, among other things, electric rates for interstate wholesale transactions. The ratemaking process is one that sets rates at levels that cover all operating expenses and taxes with a remaining balance that will enable a utility to pay a fair return on funds invested by the stockholders.

A component of any economic regulatory activity is the determination of financing and accounting rules. As a consequence of regulatory jurisdiction, regulations for financing and accounting are more critical to the electric power industry than to most other nonregulated industries. Both FERC and State commissions normally use quasi-judicial proceedings for financial and accounting regulation.

Many of the publicly owned electric utilities are self-regulated (for example, the City of Dover, Delaware), while some fall under the jurisdiction of the public utility commission within the State(s) where they provide electricity to ultimate consumers (such as, in the State of Ohio). Because of the absence of any requirement for reporting to a specific regulatory body, the accounting practices and policies of publicly owned electric utilities vary greatly. Many publicly owned electric utilities use the FERC Uniform System of Accounts or variations of this (and other) accounting systems. As a result, the composite statistics provided must be viewed with an appropriate degree of caution.

Because of the respondent burden in preparing this information, publicly owned electric utilities are permitted to use the year-end period on which their fiscal practices are based. Electric utilities must submit data for a 12-month period (does not necessarily end on December 31) and show consistency in their methods and reporting dates. Data are provided for a subset of the selected publicly owned electric utilities with the fiscal years ending June 30, and December 31, 1989.

Composite Statement of Income

This statement provides a summary of the revenue collected from consumers in return for services rendered within the reporting period; summarizes (in broad categories) the costs incurred by the electric utility in the production and delivery of electricity; and reports the net income or profit that remains for the owners of the business. Because of the somewhat unique nature of regulated electric utilities, the income statement that is standard to other nonregulated industries has been recast to reflect the reporting conventions in the electric power industry. For example, accounting for capital used in construction requires additional reporting on the income statement because of the perpetual nature of construction work in progress. Also, on occasion, electric utilities are required to defer the recovery of certain costs and earnings from consumers until a future period. This introduces additional accounting requirements, which must be reflected on all the financial statements.

Composite Balance Sheet

A summary of plant, property, and cash held by the electric utilities, as well as the receivables of the electric utilities, are represented as assets on the composite balance sheet. Future funds obligated by the electric util-

[25]Data prior to 1989 published in the Energy Information Administration, *Financial Statistics of Selected Electric Utilities*, DOE/EIA-0437(88)(Washington, DC, February 1990).

ities to acquire assets are shown as liabilities and any increased investment by stockholders is shown as capital on the balance sheet. The standard balance sheet used in the electric power industry emphasizes capital intensity while the balance sheet used by nonregulated industries emphasizes liquidity. The balance sheet represents an accounting at a particular time. For this section, the composite balance sheets are presented for investor-owned electric utilities at the end of a calendar year and for publicly owned electric utilities at the fiscal years ending June 30, and December 31, 1989.

Composite Financial Indicators

The financial statement accounts presented in this chapter represent compiled statistics resulting from the activity of the selected electric utilities. The measurement of how well the electric utility industry performs in different areas can be approximated by comparing some of the asset and income accounts to other relevant accounts. Using the financial statement information, some basic indicators that can be used to analyze or assess the financial condition of the industry are provided. The method used to derive these selected financial indicators is ratio analysis.

Investor-Owned Electric Utilities

Activity ratios evaluate how assets of the investor-owned electric utilities are managed. The electric utility industry is one of the most capital intensive industries in the United States and activity ratios are paramount indicators of the magnitude of their capital intensity. These ratios demonstrate the financial relationship, which exists between the assets and revenue, sales, and, income that these fixed and total assets generate. The ratios on *electric-fixed-asset (not plant) turnover* and *total-asset turnover* assess the effective and efficient use of assets in the generation of income.

Leverage ratios summarize the overall debt burden and debt structure of the investor-owned electric utilities. In addition, these ratios indicate the financial ability to meet debt service requirements and how well management uses leverage to increase the value of the investment of the stockholders. The financial soundness of an industry is directly related to the ability of the industry to raise capital and to be able to provide a reasonable return of and on the capital invested. In order to measure the ability to do this, a number of indicators are used. *Current assets to current liabilities* is a measure of liquidity. For example, do the investor-owned electric utilities have sufficient cash and other assets (current), which can be quickly converted to cash to cover maturing obligations (current liabilities)? *Long-term debt to capitalization, preferred stock to capitalization,* and *common-stock equity to capitalization* portray the financial structure and highlight the extent to which debt and other fixed obligations are used to finance operations. *Total debt to total assets* shows the amount of debt that has been incurred in relationship to the total assets possessed. As the value of this ratio increases, the financial risks also become greater and more apparent. *Common-stock equity to total assets* evaluates financial strength. As net worth increases in relationship to total assets, the debt portion is decreased and financial risks are lowered. *Interest coverage before taxes without AFUDC* (Allowance for Funds Used During Construction), a noncash source of income, is an indicator of the ability of the investor-owned electric utility to ensure its payment of annual interest costs and maintain its credit ratings.

Profitability ratios indicate operating effectiveness of the investor-owned electric utilities and are used to further evaluate the management of income. The *profit margin* is equal to net income divided by revenue. This ratio is used extensively and represents the overall measure of income performance. *Return on average-common-stock equity* measures the rate of return on equity capital invested. Since one of the main objectives of management is to earn the highest return permissible, this ratio is the best single measure of the effectiveness of management from the perspective of the stockholders. *Return on investment* measures the overall rate of return that has been earned on assets. This ratio, which is determined by dividing total assets into net income, provides an indicator of the overall financial performance.

Publicly Owned Electric Utilities

Ratios are provided on the publicly owned electric utilites to assist in understanding the financial performance of the publicly owned segment of the industry. Six ratios calculated from the statement of income and four ratios calculated from the balance sheet are provided. *Electric utility plant per dollar of revenue* highlights the capital intensity of the utility. *Current assets to current liabilities* provides a measure of the ease by which the utility can meet its current obligations. *Electric utility plant as a percent of total assets* represents the total gross investment in electric plant divided by the total assets of the utility. A significant variation in this ratio should signal a relatively fundamental change in the activities of the utility. *Net electric utility plant as a percent of total assets* represents the remaining book value and a significant variation should signal a change for the utility. *Accumulated provision for depreciation as a percent of total electric plant* measures the cost of recovery of the use of the assets over a period of time for a utility; an increase indicates the asset life is being used up. The ratios of *electric operating and maintenance expenses, electric depreciation and amortization, taxes and tax equivalents, contributions and services,* and *interest on long-term debt* to *electric operating revenue* are indicators of how resources were used to produce income.

Revenue and Expense Statistics

These summary statistics are basic in any analysis of the operating soundness of an electric utility. In order to conduct this analysis, it is necessary to separate the electric utility revenue and expense information from other utility revenue and expense data. Emphasis is placed on total electric operating expenses. Data are presented so that operating costs are separate from maintenance, depreciation, and taxes. For comparative purposes, the ratio of income from utility operations is included, although ratios of electric utility operating expenses are emphasized.

Data Sources

The financial statistics reported in this chapter on the investor-owned electric utilities are compiled from data extracted from the FERC Form 1, "Annual Report of Electric Utilities, Licensees and Others." This form is a restricted-universe census used annually to collect detailed accounting, financial, and operating data from selected investor-owned electric utilities having, in each of the last 3 consecutive years, sales or transmission service that exceeds any one or more of the following:

- 1 million megawatthours of total sales
- 100 megawatthours of sales for resale
- 500 megawatthours of gross interchange out or
- 500 megawatthours of wheeling for others (deliveries plus losses).

Approximately 180 investor-owned electric utilities are required to submit the FERC Form 1. These major investor-owned electric utilities represent about two-thirds of all investor-owned electric utilities. The electric utilities are required to follow the Uniform System of Accounts prescribed by the FERC (in cooperation with the National Association of Regulatory Utility Commissioners). More detailed financial statistics on investor-owned electric utilities are published in the *Financial Statistics of Selected Investor-Owned Electric Utilities.*[26]

The financial statistics on the publicly owned electric utilities are compiled from data extracted from the Form EIA-412, "Annual Report of Public Electric Utilities." This form is a restricted-universe census used annually to collect detailed accounting, financial, and operating data from selected publicly owned electric utilities having, in each of the last 2 consecutive years, sales that exceed any one of the following:

- 120,000 megawatthours of sales to ultimate consumers or
- 120,000 megawatthours of sales for resale.

Approximately 450 publicly owned electric utilities are required to submit the Form EIA-412. These selected publicly owned electric utilities represent about one-fourth of all publicly owned electric utilities and over 80 percent of total sales by publicly owned electric utilities to ultimate consumers. These electric utilities are requested, but not required, to follow the FERC Uniform System of Accounts. More detailed financial statistics on public electric utilities, Federal electric utilities, and rural electric cooperatives are published in the *Financial Statistics of Selected Publicly Owned Electric Utilities.*[27]

[26]Energy Information Administration, *Financial Statistics of Selected Investor-Owned Electric Utilities*, DOE/EIA-0437/1(89)(Washington, DC); data prior to 1989 published in the Energy Information Administration, *Financial Statistics of Selected Electric Utilities*, DOE/EIA-0437(88)(Washington, DC, February 1990).

[27]Energy Information Administration, *Financial Statistics of Selected Publicly Owned Electric Utilities*, DOE/EIA-0437/2(89)(Washington, DC); data prior to 1989 published in the Energy Information Administration, *Financial Statistics of Selected Electric Utilities*, DOE/EIA-0437(88)(Washington, DC, February 1990).

Table 31. Composite Statement of Income for Selected Investor-Owned Electric Utilities, 1987-1989

Description	1989 (thousand dollars)[1]	1988 (thousand dollars)	1987 (thousand dollars)	Percent Change	
				1989/1988	1988/1987
Operating Revenue	**167,067,596**	**159,488,265**	**153,644,845**	**4.8**	**3.8**
Electric	150,903,317	143,930,420	138,548,938	4.8	3.9
Gas	15,119,408	14,580,945	14,113,720	3.7	3.3
Other Utility	1,044,871	976,899	982,187	7.0	-.5
Operating Expenses	**136,500,226**	**129,730,357**	**125,560,389**	**5.2**	**3.3**
Electric	121,552,060	115,347,626	111,557,374	5.4	3.4
Fuel	32,937,516	31,903,430	31,474,466	3.2	1.4
Other Operating and Maintenance	54,785,240	51,752,113	47,454,042	5.9	9.1
Depreciation[2]	15,032,961	13,469,355	11,868,562	11.6	13.5
Taxes Other Than Income Taxes	10,796,423	10,319,912	9,744,870	4.6	5.9
Income Taxes	6,848,369	6,080,204	6,719,211	12.6	-9.5
Deferred Income Tax	1,479,626	2,078,160	3,737,781	-28.8	-44.4
Investment Tax Credit (Net)	-328,075	-255,548	558,440	-28.4	-145.8
Gas	13,972,207	13,473,072	13,085,106	3.7	3.0
Income Taxes	336,660	330,991	410,359	1.7	-19.3
Other	13,635,547	13,142,081	12,674,747	3.8	3.7
Other Utility	975,958	909,659	917,909	7.3	-.9
Income Taxes	16,480	15,921	8,667	3.5	83.7
Other	959,478	893,738	909,242	7.4	-1.7
Operating Income	**30,567,370**	**29,757,908**	**28,084,456**	**2.7**	**6.0**
Electric	29,351,256	28,582,794	26,991,564	2.7	5.9
Gas	1,147,200	1,107,873	1,028,614	3.5	7.7
Other	68,913	67,240	64,278	2.5	4.6
Other Income and Deductions	**2,560,660**	**2,039,670**	**5,517,703**	**25.5**	**-63.0**
Allowance for Other Funds Used During Construction	1,202,004	1,615,721	3,076,304	-25.6	-47.5
Less Taxes	943,175	1,070,681	1,230,042	-11.9	-13.0
Deferred Earnings (Misc.) (acct 421)	1,073,178	1,898,737	1,638,492	-43.5	15.9
Less Other Income and Expenses[3]	-1,228,653	404,107	-2,032,949	**NM**	**NM**
Total Income Before Interest Charges	**33,128,030**	**31,797,578**	**33,602,159**	**4.2**	**-5.4**
Net Interest Charges	**14,852,295**	**14,386,924**	**13,621,908**	**3.2**	**5.6**
Interest Expense	15,648,011	15,333,123	15,217,562	2.1	.8
Less Allowance for Borrowed Funds Used During Construction	1,142,007	1,261,283	1,864,473	9.5	32.4
Other Charges--Net	346,291	315,084	268,820	9.9	17.2
Net Income Before Extraordinary Charges	**18,275,735**	**17,410,653**	**19,980,251**	**5.0**	**-12.9**
Less **Extraordinary Items After Taxes**[3]	**962,974**	**1,368,946**	**955,520**	**-29.7**	**43.3**
Net Income	**17,312,761**	**16,041,707**	**19,024,731**	**7.9**	**-15.7**
Preferred Stock Dividend Requirements	**2,417,239**	**2,264,454**	**2,297,668**	**6.7**	**-1.4**
Earnings Available for Common	**14,895,522**	**13,777,253**	**16,727,063**	**8.1**	**-17.6**
Common Dividends	**14,030,562**	**13,517,681**	**12,953,664**	**3.8**	**4.4**
Additions to Retained Earnings	**705,327**	**-13,385**	**2,601,817**	**NM**	**NM**
Average Shares of Common Stock Outstanding	**5,824,221**	**5,400,881**	**5,334,851**	**7.8**	**1.2**
Earnings Available Per Average Common Share (Dollars)	**2.56**	**2.55**	**3.14**	**.3**	**-18.6**

[1] Data for 1989 are preliminary.
[2] Includes amortization and depletion.
[3] Other Income and Expenses and Extraordinary Items After Taxes were affected negatively by aftertax write offs, accounting adjustments, and regulatory rate decisions. The majority of the charges were directly related to the the treatment of nuclear plants.

NM = Not meaningful.

Notes: •Totals may not equal sum of components because of independent rounding. •Percent change is calculated before rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Table 32. Composite Balance Sheet for Selected Investor-Owned Electric Utilities, 1987-1989

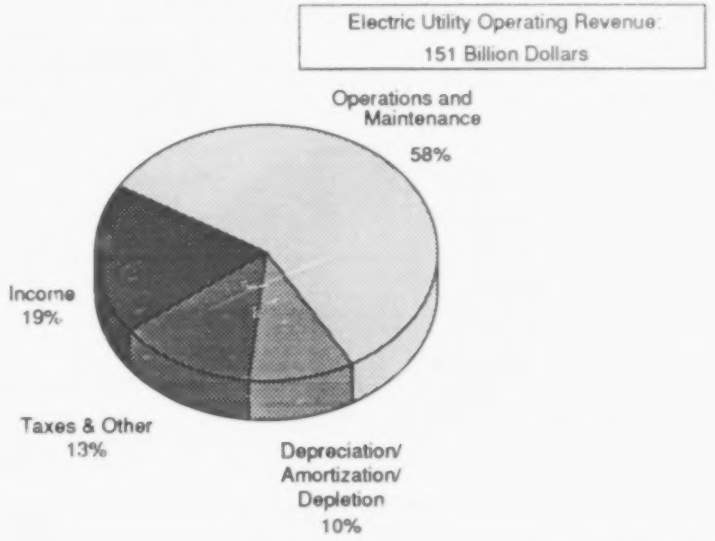
Description	1989 (thousand dollars)[1]	1988 (thousand dollars)	1987 (thousand dollars)	Percent Change	
				1989/1988	1988/1987
Assets					
Utility Plant - Net	**363,223,394**	**361,638,256**	**356,982,995**	**0.4**	**1.3**
Electric Utility Plant - Net	337,460,182	335,866,884	331,357,356	.5	1.4
Electric Utility Plant	428,700,561	409,092,233	383,532,411	4.8	6.7
Construction Work in Progress	33,714,555	40,298,296	51,029,217	-16.3	-21.0
Less Accumulated Depreciation	124,954,934	113,523,644	103,204,272	10.1	10.0
Nuclear Fuel - Net	8,700,644	9,642,680	10,386,899	-9.8	-7.2
Other Utility Plant - Net	17,062,569	16,128,691	15,238,740	5.8	5.8
Other Property and Investments	**16,136,757**	**15,200,683**	**15,561,593**	**6.2**	**-2.3**
Current and Accrued Assets	**41,516,163**	**39,122,286**	**40,857,341**	**6.1**	**-4.2**
Deferred Debits	**44,846,622**	**38,335,664**	**32,868,949**	**17.0**	**16.6**
Total Assets	**465,722,937**	**454,296,889**	**446,270,877**	**2.5**	**1.8**
Capitalization and Liabilities					
Capitalization	**334,068,968**	**329,813,736**	**328,114,562**	**1.3**	**.5**
Common Stock Equity (End of Year)	145,175,878	142,715,825	142,931,813	1.7	-.2
Common Stock	94,602,732	93,158,701	92,284,680	1.6	.9
Retained Earnings (Adjusted)	50,573,146	49,557,124	50,647,133	2.1	-2.2
Preferred Stock	25,944,650	26,371,225	26,761,357	-1.6	-1.5
Long-term Debt	162,948,440	160,726,686	158,421,392	1.4	1.5
Current and Other Liabilities	**131,653,970**	**124,483,152**	**118,156,315**	**5.8**	**5.4**
Other Noncurrent Liabilities	7,803,119	7,711,888	7,289,977	1.2	5.8
Current and Accrued Liabilities	42,023,659	38,412,073	39,344,892	9.4	-2.4
Deferred Credits	81,827,192	78,359,191	71,521,446	4.4	9.6
Accumulated Deferred Income Taxes	53,328,188	50,247,264	45,917,405	6.1	9.4
Accumulated Deferred Investment Tax Credit	15,886,418	16,792,695	17,275,481	-5.4	-2.8
Other Deferred Credits (Adjusted)	12,612,586	11,319,232	8,328,561	11.4	35.9
Total Capitalization and Liabilities	**465,722,937**	**454,296,889**	**446,270,877**	**2.5**	**1.8**

[1] Data for 1989 are preliminary.

Notes: •Totals may not equal sum of components because of independent rounding. •Percent change is calculated before rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Figure 21. The Revenue Dollar from Operations for Selected Investor-Owned Electric Utilities, 1989



Note: Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Table 33. Composite Financial Indicators for Selected Investor-Owned Electric Utilities, 1987-1989

Description[1]	1989[2]	1988	1987
Activity			
1. Electric Fixed Asset (Net Plant) Turnover	0.45	0.43	0.42
2. Total Asset Turnover	.36	.35	.34
Leverage			
3. Current Assets to Current Liabilities	.99	1.02	1.04
4. Long-term Debt to Capitalization	48.78	48.73	48.28
5. Preferred Stock to Capitalization	7.77	8.00	8.16
6. Common Stock Equity to Capitalization	43.46	43.27	43.56
7. Total Debt to Total Assets[3]	36.26	36.67	37.18
8. Common Stock Equity to Total Assets	31.17	31.42	32.03
9. Interest Coverage Before Taxes without AFUDC[4]	2.46	2.35	2.42
Profitability			
10. Profit Margin	10.36	10.06	12.38
11. Return on Average Common Stock Equity[5]	12.03	11.23	13.49
12. Return on Investment	3.72	3.53	4.26

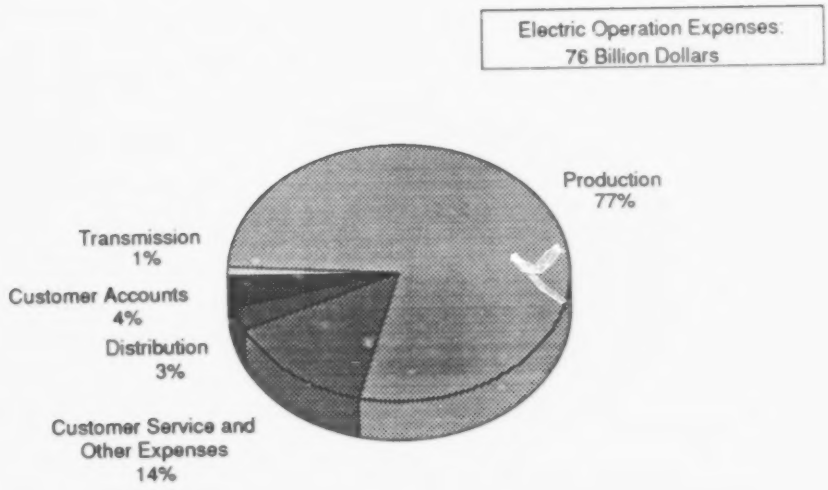
[1] Indicators 1, 2, 3, and 9 are ratios. Indicators 4 through 8 and 10 through 12 are percentages.
[2] Data for 1989 are preliminary.
[3] Total debt is the sum of Long-term Debt and Short-term Debt. The values for Short-term Debt included in Current and Accrued Liabilities (Notes Payable) were $5,928,421 for 1989; $5,843,202 for 1988; and $7,500,551 for 1987.
[4] Taxes Other Than Income Taxes (included in Other Income and Expenses-Net) should be added to Taxes from Other Income and Deductions. The values were $251,243 for 1989; $552,805 for 1988; and $399,495 for 1987.
[5] The Average Common Stock Equity is the average of the beginning and ending year balances. The values for the beginning of each year were $142,715,825 for 1989; $142,931,813 for 1988; and$139,050,743 for 1987.

AFUDC = Allowance for Funds Used During Construction.

Notes: •Formulas for computing the financial indicators are in Appendix C. •Indicators 4, 5, and 6 may not sum to 100 percent because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Figure 22. Share of Electric Operation Expenses for Selected Investor-Owned Electric Utilities, 1989



Note: Totals may not equal sum of components because of independent rounding.
Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Table 34. Revenue and Expense Statistics for Selected Investor-Owned Electric Utilities, 1987-1989

Description	1989 (thousand dollars)[1]	1988 (thousand dollars)	1987 (thousand dollars)	Percent Change	
				1989/1988	1988/1987
Utility Operating Revenue	**167,067,596**	**159,488,265**	**153,644,845**	**4.8**	**3.8**
Electric Utility	150,903,317	143,930,420	138,548,938	4.8	3.9
Other Utility	16,164,279	15,557,844	15,095,907	3.9	3.1
Utility Operating Expenses	**136,500,226**	**129,730,357**	**125,560,389**	**5.2**	**3.3**
Electric Utility	121,552,060	115,347,626	111,557,374	5.4	3.4
Operation	76,451,124	72,742,004	68,616,305	5.1	6.0
Production	59,235,893	56,186,332	52,889,982	5.4	6.2
Cost of Fuel	32,937,516	31,903,430	31,474,466	3.2	1.4
Purchased Power	17,959,051	16,061,339	14,719,739	11.8	9.1
Other	8,339,326	8,221,563	6,695,777	1.4	22.8
Transmission	1,113,547	1,026,861	983,285	8.4	4.4
Distribution	2,393,944	2,331,160	2,232,547	2.7	4.4
Customer Accounts	2,992,829	2,894,179	2,826,170	3.4	2.4
Customer Service	959,473	887,963	850,576	8.1	4.4
Sales	208,655	177,006	142,154	17.9	24.5
Administrative and General	9,546,783	9,238,502	8,691,593	3.3	6.3
Maintenance	11,271,632	10,913,539	10,312,203	3.3	5.8
Depreciation	15,032,961	13,469,355	11,868,562	11.6	13.5
Taxes	18,796,343	18,222,728	20,760,304	3.1	-12.2
Other Utility	14,948,165	14,382,731	14,003,015	3.9	2.7
Income From Utility Operations	**30,567,370**	**29,757,908**	**28,084,456**	**2.7**	**6.0**

[1] Data for 1989 are preliminary.

Notes: •Totals may not equal sum of components because of independent rounding. •Percent change is calculated before rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Table 35. Revenue and Expense Percentages for Selected Investor-Owned Electric Utilities, 1987-1989

Description	1989[1]	1988	1987
Utility Operating Revenue	**100.0**	**100.0**	**100.0**
Electric Utility	90.3	90.2	90.2
Other Utility	9.7	9.8	9.8
Utility Operating Expenses	**81.7**	**81.3**	**81.7**
Electric Utility	72.8	72.3	72.6
Operation	45.8	45.6	44.7
Production	35.5	35.2	34.4
Cost of Fuel	19.7	20.0	20.5
Purchased Power	10.7	10.1	9.6
Other	5.0	5.2	4.4
Transmission	.7	.6	.6
Distribution	1.4	1.5	1.5
Customer Accounts	1.8	1.8	1.8
Customer Service	.6	.6	.6
Sales	.1	.1	.1
Administrative and General	5.7	5.8	5.7
Maintenance	6.7	6.8	6.7
Depreciation	9.0	8.4	7.7
Taxes	11.3	11.4	13.5
Other Utility	8.9	9.0	9.1
Income From Utility Operations	**18.3**	**18.7**	**18.3**

[1] Data for 1989 are preliminary.

Note: Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others." See Appendix C for a detailed description of this restricted-universe census.

Table 36. Composite Statement of Income for Selected Publicly Owned Electric Utilities, 1989
(Thousand Dollars)

Description	Utilities with Financial Year Ending on June 30	Utilities with Financial Year Ending on Dec 31
Operating Revenue - Electric	**9,582,378**	**10,389,832**
Operating Expenses - Electric	**8,405,559**	**8,880,380**
Operation Excluding Fuel	6,681,855	6,928,383
Fuel	991,965	944,057
Maintenance	627,818	670,012
Depreciation and Amortization	749,056	964,623
Taxes and Tax Equivalents	152,282	261,476
Net Contributions and Services	194,548	55,886
Operating Income - Electric	**1,176,819**	**1,509,451**
Other Income and Deductions	**481,567**	**1,213,604**
Income from Electric Plant Leased to Others	851	2,033
Allowance for Funds Used During Construction	9,624	133,414
Other Income Net	471,092	1,078,157
Total Income Before Interest Charges	**1,658,386**	**2,723,055**
Net Interest Charges	**1,185,696**	**2,436,983**
Interest Expenses	1,176,449	2,230,716
Other Income Deductions	9,247	206,267
Net Income Before Extraordinary Charges	**472,690**	**286,072**
Less **Extraordinary Items**	29,173	602,837
Net Income	**443,517**	[1] **-316,766**

[1] Net income reflects $584 million of extraordinary deduction associated with the abandonment of the Rancho Seco Nuclear Plant reported by the Sacramento Municipal Utility District.

Notes: •Totals may not equal sum of components because of independent rounding. The number of publicly owned electric utilities for end of period is 188 for June 30 and 185 for December 31. •Data for 1989 are preliminary.

Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities." See Appendix C for a detailed description of this restricted-universe census.

Table 37. Composite Balance Sheet for Selected Publicly Owned Electric Utilities, 1989
(Thousand Dollars)

Description	Utilities with Financial Year Ending on June 30	Utilities with Financial Year Ending on Dec 31
Assets		
Electric Utility Plant-Net	**19,550,307**	**26,458,430**
Electric Utility Plant	25,420,178	34,940,450
Accumulated Provision for Depreciation and Amortization	5,869,872	8,492,020
Other Property and Investments	**7,831,766**	**5,863,561**
Current and Accrued Assets	**4,838,710**	**7,642,044**
Deferred Debits	**3,564,662**	**4,173,424**
Total Assets	**35,785,444**	**44,137,458**
Liabilities and Other Credits		
Investment of Municipality - Surplus	**10,204,736**	**8,303,481**
Long-Term Debt	**20,220,539**	**31,179,275**
Other Noncurrent Liabilities	**47,664**	**328,214**
Current and Accrued Liabilities	**3,921,846**	**2,598,378**
Deferred Credits	**1,390,658**	**1,728,111**
Total Liabilities and Other Credits	**35,785,444**	**44,137,458**

Notes: •Totals may not equal sum of components because of independent rounding. The number of publicly owned electric utilities for end of period is 188 for June 30 and 185 for December 31. •Data for 1989 are preliminary.

Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities." See Appendix C for a detailed description of this restricted-universe census.

Table 38. Composite Financial Indicators for Selected Publicly Owned Electric Utilities, 1989
(Thousand Dollars)

Description	Utilities with Financial Year Ending on June 30	Utilities with Financial Year Ending on Dec 31
Electric Utility Plant per Dollar of Revenue	2.7	3.4
Current Assets to Current Liabilities	1.2	2.9
Electric Utility Plant as a Percent of Total Assets	71.0	79.2
Net Electric Utility Plant as a Percent of Total Assets	54.6	59.9
Accumulated Provision for Depreciation as a Percent of Electric Utility Plant	23.1	24.3
Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenues	76.3	73.1
Electric Depreciation and Amortization as a Percent of Electric Operating Revenues	7.8	9.3
Taxes and Tax Equivalents as a Percent of Electric Operating Revenues	1.6	2.5
Net Contributions and Services as a Percent of Electric Operating Revenues	2.0	.5
Interest Expenses as a Percent of Electric Operating Revenues	12.3	21.5

Notes: •Totals may not equal sum of components because of independent rounding. The number of publicly owned electric utilities for end of period is 188 for June 30 and 185 for December 31. •Data for 1989 are preliminary.
Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities." See Appendix C for a detailed description of this restricted-universe census.

Table 39. Revenue and Expense Statistics for Selected Publicly Owned Electric Utilities, 1989
(Thousand Dollars)

Description	Utilities with Financial Year Ending on June 30	Utilities with Financial Year Ending on Dec 31
Operating Revenue - Electric	9,582,378	10,389,832
Operating Expenses - Electric	8,405,559	8,880,380
Operation	6,681,655	6,928,383
Production	5,666,225	5,521,546
Transmission	67,686	354,133
Distribution	266,525	178,555
Customer Accounts	120,779	127,636
Customer Service	22,503	43,294
Sales	7,133	6,834
Administrative and General	531,002	696,385
Maintenance	627,818	670,012
Depreciation and Amortization	749,056	964,623
Taxes and Tax Equivalents	152,282	261,476
Net Contributions and Services	194,548	55,886
Income from Electric Utility Operations	1,176,819	1,509,451

Notes: •Totals may not equal sum of components because of independent rounding. The number of publicly owned electric utilities for end of period is 188 for June 30 and 185 for December 31. •Data for 1989 are preliminary.
Source: Energy Information Administration, Form EIA-412, "Annual Report of Public Electric Utilities." See Appendix C for a detailed description of this restricted-universe census.

Environmental Statistics

When fossil fuels are burned in the production of electricity, a variety of gases and particulates are formed. If these gases and particulates are not captured by some pollution control equipment, they are released into the atmosphere. This chapter provides a brief summary of these gaseous emissions and the methods employed to reduce or eliminate their release into the atmosphere.

Background

Among the gases emitted during the burning of fossil fuels are sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2). Coal-fired generating units produce more sulfur dioxide and nitrogen oxides than other fossil-fuel units for two reasons. First, because coal generally contains more sulfur than other fossil fuels, it creates more sulfur dioxide when burned. Second, more nitrogen oxide emissions are associated with coal-fired plants than with other fossil-fueled plants because more coal-fired generating capacity is in use.

Sulfur is an element that is present in almost all coal, although some kinds of coal contain more sulfur than others depending on the geographic location of the coal mine and the type of coal being mined. Western coal has less sulfur than eastern coal. Over one-half of the coal mined in the West is subbituminous coal that is low in sulfur content (less than 0.5 percent) and contains approximately 8,000 Btu per pound. Eastern coal, or bituminous coal can exceed 8 percent sulfur and a heat content of over 12,000 Btu per pound. The average percent of sulfur contained in coal ranges from 0.3 percent in the West to approximately 2.5 percent in the East. During combustion, the sulfur combines with the oxygen in the air to form *sulfur dioxide*. As the sulfur dioxide mixes further with oxygen and trace substances in the air, a variety of sulfate compounds emerges. How these transformations take place, and in what proportions, is a subject of vigorous research. The behavior of sulfur emissions depends partly on the type of coal used and how it is burned. In addition, the presence of light, moisture, and other pollutants in the atmosphere may also be important in triggering the complex changes that sulfur emissions undergo. To a lesser degree, sulfur is also contained in petroleum and varies according to the type of petroleum (for example, light oil, heavy oil, etc.). Petroleum can range from almost no sulfur to about 5 percent sulfur. The average percent of sulfur contained in petroleum consumed by fossil-steam plants ranges from about 0.05 percent in western plants to about 2.75 percent for plants in the East. The amount of sulfur contained in gas is insignificant.

Nitrogen is a colorless, odorless gas that makes up about 78 percent of the atmosphere. Nitrogen combines with oxygen and water to form several *nitrogen oxides*. The most important is nitrogen dioxide, one of the compounds that gives photochemical smog its characteristic yellowish-brown color. Only about 10 percent of the nitrogen compounds in the air are the result of human activity. The rest are formed by natural processes, such as the decay of organic matter. However, since the human-made 10 percent is emitted mostly in industrial urban areas, concentration there can become high enough to cause concern.

Sulfur dioxide and nitrogen oxides are referred to as precursors to acid deposition, because, under the right set of conditions, they react with other chemicals in the atmosphere to form sulfuric acid and nitric acid, respectively. These two acids do not accumulate in the atmosphere, but are absorbed by rain droplets, thus cleansing the atmosphere and discharging acid onto the earth in the form of "acid rain." In addition, sulfuric acid may form microscopic droplets that can be deposited directly onto the ground. This form of deposition, as well as the direct capture of sulfur dioxide by vegetation, is referred to as dry deposition.

Carbon dioxide is a colorless, odorless, nontoxic gas formed by the combustion of carbon and carbon compounds found in coal, petroleum, and gas. Currently, the only way to limit the emission of carbon dioxide when burning fossil fuels is expensive. Efforts, however, are underway to determine what methods can be employed to reduce or eliminate the release of carbon dioxide from power plants. Tail gas cleanup (carbon dioxide scrubbing) is currently the only technological option. This option would require the adaptation by the electric utility industry of acid gas removal technologies used by the petroleum and petrochemical industries. Because of the potential expense involved, no emission standards or required reductions exist.

However, the Department of Energy is developing clean coal technologies (such as pressurized fluidized bed combustion) for new plants and repowering applications. Due to the increased conversion efficiencies of these technologies, carbon dioxide emissions are re-

duced. For each 5-percentage-point improvement in conversion efficiency, carbon dioxide emissions are reduced by 10 to 15 percent. Carbon dioxide is normally removed from the atmosphere by green plants. The increased use of fossil fuels in recent years, as well as extensive deforestation, has caused a buildup of carbon dioxide in the atmosphere. This increase of carbon dioxide causes the atmosphere to absorb infrared radiation reflected from the earth that would otherwise have been dissipated into space. This phenomenon increases temperature and is called the "greenhouse" effect because it is similar to the trapping of the energy of the sun in a greenhouse. These increasing temperatures are of potential concern because they could cause dramatic climatic changes, shifts in agricultural zones, and partial melting of the polar ice caps resulting in flooding of coastal areas. However, significant uncertainties exist regarding global warming, and no conclusions can be drawn regarding future warming based on past temperature records.

Emission Standards

To respond to concerns about emissions of sulfur dioxide and nitrogen oxides as well as several other air pollutants, Congress passed the Clean Air Act (CAA) in 1963. It was not until 1970, however, that the Environmental Protection Agency was empowered to set enforceable air quality standards. In 1971, this Agency established New Source Performance Standards (NSPS) that required coal-fired utility boilers built after August 17, 1971, to emit no more than 1.2 pounds of sulfur dioxide per million Btu of heat input. Requirements for nitrogen oxides were more complex, with allowable limits ranging from 0.2 pounds per million Btu to 0.8 pounds per million Btu, depending on the type of fuel burned and the combustion device used.

In 1977, Congress amended the CAA to require States to set limits on existing sources in regions not attaining goals established in the Act. In 1979, the Environmental Protection Agency established the Revised New Source Performance Standards (RNSPS). The new standards retain the 1971 NSPS of 1.2 pounds of sulfur dioxide per million Btu of heat input, but require sulfur dioxide emissions from all new or modified (post 1978) boilers to be reduced by at least 90 percent unless 90-percent removal reduces emissions to less than 0.6 pounds per million Btu. If emissions fall below that level, reductions between 70 and 90 percent are permitted, depending on the sulfur content of the coal. RNSPS for nitrogen oxides are complex and, as with NSPS, set limits varying from 0.2 to 0.8 pounds per million Btu, depending on the type of fuel burned and combustion device used. RNSPS for nitrogen oxides differ from NSPS in the number of categories of combustion into which they are divided.

The Clean Air Act Amendments of 1990 was signed into law by President Bush on November 15, 1990. The goal of the bill is a 10-million-ton reduction in sulfur dioxide emissions and a 2-million-ton reduction in nitrogen oxide emissions from 1980 levels. The sulfur dioxide reduction is to be achieved in two phases. The first phase is a 5-million-ton reduction to be achieved by 1995. The second phase is an additional 5-million-ton reduction to occur after 1999.

Emission Reductions

Sulfur Dioxide. One method available to reduce the sulfur dioxide emitted when burning coal, is to switch to a coal that has a lower sulfur content. Emissions of sulfur dioxide may also be reduced by using less-polluting fuels, particularly gas. Another approach is to install equipment designed to remove sulfur dioxide from the gas (flue gas) released through the flues of the plant. Additional methods for reducing emissions of sulfur dioxide, which include converting boilers to the fluidized-bed combustion process and employing the technology of integrated-gasification combined cycle, are currently under study and not in extensive use.

Nitrogen Oxides. Formation of nitrogen oxides is less dependent on the type of fuel burned than on how the fuel is burned. Apart from the nitrogen content of the fuel, the extent of nitric-oxide formation depends primarily on the combustion temperature. Nitrogen-oxide emissions can be reduced by low-excess-air firing; low-combustion temperatures; use of low-nitrogen fuels (such as natural gas and light distillate oil); staged combustion in which localized fuel-rich conditions are created where both thermal and fuel nitrogen oxides are minimized; and, use of low-nitrogen-oxide burners and fluidized-bed combustion.

Environmental Equipment

While not the only kind of environmental equipment installed at power plants, flue gas desulfurization units, particulate collectors, and cooling towers are the most significant. In a flue gas desulfurization unit (scrubber), the gases resulting from combustion are passed through tanks containing a material that captures and neutralizes the sulfur dioxide. Particulate matter is most frequently removed from the combustion gases by either filtering (a series of filter bags that trap the ash and dust much like a household vacuum cleaner) in a baghouse or with an electrostatic precipitator. In the latter, the particulates are given an electric charge and collected. Particulate collection is mainly centered on coal combustion because of the large percentage of ash that coal contains. Petroleum has very little ash and natural gas has practically none. A cooling tower is a structure for transferring heat in the water to the atmosphere. The most common type of cooling tower is the wet tower, also called the evaporative tower. In a wet tower, cooling is caused mainly by evaporation of the water and partly by direct-heat transfer.

For a fossil-fueled steam-electric generating unit, about two-thirds of the heat produced by burning the fuel is released to the environment, and only about one-third is used to produce electricity. Most waste heat (contained in the cooling water) is dissipated into a body of water, such as a river, lake, or bay. Cooling towers are installed where there is insufficient cooling water and where the waste heat discharged into the cooling water affects plants or marine life.[28]

Environmental equipment can be a significant part of the cost of a power plant. This additional cost includes the initial capital cost of installation and the recurring operation and maintenance (O&M) cost. Capital costs are given as a cost per kilowatt of installed nameplate capacity in dollars per megawatt.

Data Sources

Estimates are provided in the following tables on sulfur dioxide, nitrogen oxide, and carbon dioxide emissions from fossil-fueled steam-electric generating units. The methodology for computing emission estimates is described in Appendix C. Additional detailed information on emissions can be obtained in Chapter 4 and Appendix C of the *Annual Outlook for U. S. Electric Power 1989*.[29] Also presented in the following tables are the number and capacity of fossil-fueled steam-electric generators with environmental equipment (scrubbers, particulate collectors, and cooling towers). Because power plants can have more than one type of environmental equipment, the generators at these plants can be included in more than one category. Also, not all plants have environmental equipment. Data regarding the quality of fossil fuels used to produce electricity, including heat, sulfur, and ash content, are also provided in the following tables. Lastly, average flue gas desulfurization costs (that is, operation and maintenance costs per kilowatthour of generation and installation costs per kilowatt of nameplate capacity) are presented.

These estimates were either derived or obtained directly from the Form EIA-767, "Steam-Electric Plant Operation and Design Report." This form is a restricted-universe census used to collect boiler-specific data from almost 900 power plants with a fossil-fueled steam-electric nameplate capacity of 10 or more megawatts operated by over 300 electric utilities. The entire form, including data on environmental equipment, is filed by about 700 power plants with a nameplate capacity of 100 or more megawatts. Information on power plants with a nameplate capacity between 10 and 100 megawatts is submitted only for fuel consumption and flue gas desulfurization equipment.

[28]For a more detailed discussion of environmental equipment, see Energy Information Administration, *Annual Outlook for U.S. Electric Power* DOE/EIA-0474(85) (Washington, DC, August 1985).

[29]Energy Information Administration, *Annual Outlook for U. S. Electric Power 1989* DOE/EIA-0474(89) (Washington, DC, June 1989).

Table 40. Emissions from Fossil-Fueled Steam-Electric Generating Units, 1985-1989
(Thousand Short Tons)

Emission	1989[1]	1988	1987	1986	1985
Sulfur Dioxide (SO2)	16,685	R 16,636	R 16,170	R 16,191	R 16,171
Nitrogen Oxides (NOx) ...	7,183	R 7,091	R 6,796	R 6,571	R 6,626
Carbon Dioxide (CO2)	1,996,904	R 1,969,272	R 1,876,325	R 1,809,186	R 1,798,370

[1] Data for 1989 are preliminary.
R = Revised data; data for 1985 through 1988 are revised. (See Appendix C for an explanation).
Notes: •Data include petroleum coke. •These data are estimates derived from Form EIA-767, "Steam-Electric Plant Operation and Design Report." (See Appendix C for methodology).
Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Table 41. Number and Capacity of Fossil-Fueled Steam-Electric Generators for Plants with Environmental Equipment, 1985-1989

Environmental Equipment	Scrubbers		Particulate Collectors	
	Number of Generators	Capacity[1] (megawatts)	Number of Generators	Capacity[1] (megawatts)
1989[2]	160	68,911	1,211	348,652
1988	R 158	R 68,396	R 1,211	R 349,227
1987	R 156	R 67,257	R 1,211	R 346,415
1986	R 155	R 65,261	R 1,221	R 344,946
1985	R 148	R 60,440	R 1,220	R 340,115

	Cooling Towers		Total[3]	
	Number of Generators	Capacity[1] (megawatts)	Number of Generators	Capacity[1] (megawatts)
1989[2]	555	175,033	1,433	379,954
1988	R 498	R 164,202	R 1,419	R 377,870
1987	R 537	R 170,676	R 1,431	R 377,742
1986	R 537	R 168,898	R 1,444	R 376,498
1985	R 540	R 163,177	R 1,452	R 371,927

[1] Nameplate capacity.
[2] Data for 1989 are preliminary.
[3] Components are not additive since some generators are included in more than one category and not all units have environmental equipment.
R = Revised data; data for 1985 through 1988 are revised. (See Appendix C for an explanation).
Notes: •These data are only for plants with a fossil-fueled steam-electric capacity of 100 or more megawatts. •Data include petroleum coke. •These data are estimates derived from Form EIA-767, "Steam-Electric Plant Operation and Design Report.", (See Appendix C for methodology).
Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Table 42. Emissions from Fossil-Fueled Steam-Electric Generating Units by Census Division and State, 1989 and 1988

(Thousand Short Tons)

Census Division State	1989[1]			1988[2]		
	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide
New England	**430**	**156**	**54,258**	**427**	**150**	**52,592**
Connecticut	66	26	13,335	62	25	12,936
Maine	15	5	2,854	15	5	2,756
Massachusetts	267	97	31,332	263	91	29,906
New Hampshire	80	26	6,194	82	27	6,160
Rhode Island	2	2	532	5	2	832
Vermont	0	0	11	0	0	2
Middle Atlantic	**1,782**	**628**	**209,550**	**1,793**	**607**	**202,675**
New Jersey	90	69	17,127	86	63	15,548
New York	426	169	73,864	388	154	68,375
Pennsylvania	1,266	390	118,559	1,319	390	118,752
East North Central	**5,517**	**1,753**	**399,053**	**5,414**	**1,727**	**391,966**
Illinois	889	320	59,487	905	329	61,613
Indiana	1,564	475	104,302	1,499	454	96,169
Michigan	404	278	73,365	422	279	74,672
Ohio	2,370	536	124,813	2,285	518	122,078
Wisconsin	290	144	37,086	303	147	37,434
West North Central	**1,633**	**775**	**191,585**	**1,614**	**762**	**191,671**
Iowa	189	98	28,572	197	93	27,923
Kansas	169	107	29,046	157	108	29,480
Minnesota	152	107	33,547	152	101	31,911
Missouri	886	272	54,191	863	259	53,840
Nebraska	47	70	14,031	50	72	14,770
North Dakota	160	102	28,997	164	110	30,391
South Dakota	30	19	3,201	31	19	3,386
South Atlantic	**3,651**	**1,338**	**390,220**	**3,645**	**1,295**	**374,487**
Delaware	85	31	9,494	118	34	10,476
District of Columbia	4	1	716	3	1	517
Florida	712	322	94,834	718	314	90,481
Georgia	835	216	64,870	896	220	66,825
Maryland	298	102	30,981	277	92	27,546
North Carolina	351	172	51,312	320	159	46,903
South Carolina	170	83	25,190	173	80	24,129
Virginia	189	86	29,095	163	75	24,965
West Virginia	1,007	325	83,728	977	320	82,345
East South Central	**2,194**	**721**	**185,554**	**2,305**	**775**	**199,096**
Alabama	564	193	55,300	502	179	51,072
Kentucky	751	306	70,954	809	346	80,166
Mississippi	117	45	12,449	141	53	15,205
Tennessee	762	177	46,851	853	197	52,653
West South Central	**849**	**937**	**296,064**	**815**	**911**	**291,096**
Arkansas	67	73	23,232	72	76	24,067
Louisiana	91	123	37,234	90	120	36,711
Oklahoma	96	124	37,150	97	127	37,535
Texas	595	617	198,448	556	588	192,783
Mountain	**522**	**668**	**214,583**	**521**	**656**	**210,096**
Arizona	133	123	37,505	117	106	31,958
Colorado	98	111	33,184	112	106	31,688
Idaho	NA	NA	NA	NA	NA	NA
Montana	29	61	19,051	29	62	19,260
Nevada	61	62	20,238	68	65	21,504
New Mexico	72	89	31,853	66	84	30,298
Utah	44	85	30,864	39	86	30,410
Wyoming	85	137	41,888	90	147	44,978
Pacific Contiguous	**80**	**192**	**48,665**	**76**	**193**	**48,464**
California	15	149	38,278	14	151	38,506
Oregon	2	2	539	0	0	0
Washington	63	41	9,848	62	42	9,958
Pacific Noncontiguous	**27**	**15**	**7,372**	**26**	**15**	**7,129**
Alaska	1	1	480	1	1	474
Hawaii	26	14	6,892	25	14	6,655
U.S. Total	**16,685**	**7,183**	**1,996,904**	**16,636**	**7,091**	**1,969,272**

[1] Data for 1989 are preliminary.
[2] Data for 1988 are revised; See Appendix C for an explanation.
NA = Not applicable.
Notes: •Totals may not equal sum of components because of independent rounding. •Data include petroleum coke. •These data are estimates derived from Form EIA-767, "Steam-Electric Plant Operation and Design Report.", (See Appendix C for methodology).
Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Table 43. Emissions from Fossil-Fueled Steam-Electric Generating Units by Fossil Fuel, Census Division, and State, 1989

(Thousand Short Tons)

Census Division State	Coal			Petroleum			Gas		
	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide	Sulfur Dioxide	Nitrogen Oxides	Carbon Dioxide
New England	**183**	**74**	**17,787**	**267**	**71**	**33,412**	**0**	**11**	**3,059**
Connecticut	10	7	2,438	56	19	10,693	0	0	204
Maine	0	0	0	15	5	2,854	0	0	0
Massachusetts	106	46	12,119	161	41	16,487	0	10	2,726
New Hampshire	47	21	3,230	33	5	2,964	0	0	0
Rhode Island	0	0	0	2	1	407	0	1	125
Vermont	0	0	0	0	0	7	0	0	4
Middle Atlantic	**1,597**	**497**	**148,107**	**185**	**91**	**48,417**	**0**	**40**	**13,026**
New Jersey	76	47	9,379	14	12	5,265	0	10	2,483
New York	267	71	26,949	159	68	36,466	0	30	10,449
Pennsylvania	1,254	379	111,779	12	11	6,686	0	0	94
East North Central	**5,505**	**1,725**	**391,266**	**12**	**7**	**3,342**	**0**	**21**	**4,445**
Illinois	886	317	58,007	3	2	1,085	0	1	395
Indiana	1,564	456	100,581	0	1	185	0	18	3,536
Michigan	397	273	71,444	7	3	1,541	0	2	380
Ohio	2,368	535	124,287	2	1	489	0	0	37
Wisconsin	290	144	36,947	0	0	42	0	0	97
West North Central	**1,632**	**770**	**189,715**	**1**	**0**	**308**	**0**	**5**	**1,562**
Iowa	189	97	26,399	0	0	31	0	1	142
Kansas	169	104	27,982	0	0	68	0	3	996
Minnesota	152	106	33,270	0	0	32	0	1	245
Missouri	885	272	54,050	1	0	92	0	0	39
Nebraska	47	70	13,857	0	0	42	0	0	132
North Dakota	160	102	28,962	0	0	35	0	0	0
South Dakota	30	19	3,185	0	0	8	0	0	8
South Atlantic	**3,401**	**1,214**	**342,290**	**250**	**83**	**36,330**	**0**	**41**	**11,600**
Delaware	70	20	6,548	15	8	2,266	0	3	680
District of Columbia	0	0	0	4	1	716	0	0	0
Florida	544	235	62,127	168	52	23,243	0	35	9,464
Georgia	835	216	64,751	0	0	88	0	0	31
Maryland	252	84	23,845	46	15	6,051	0	3	1,085
North Carolina	351	172	51,156	0	0	156	0	0	0
South Carolina	170	83	25,013	0	0	63	0	0	114
Virginia	172	80	25,340	17	6	3,536	0	0	219
West Virginia	1,007	324	83,510	0	1	211	0	0	7
East South Central	**2,182**	**709**	**182,069**	**12**	**3**	**1,087**	**0**	**9**	**2,398**
Alabama	561	193	55,106	0	0	88	0	0	106
Kentucky	751	306	70,809	0	0	125	0	0	20
Mississippi	105	33	9,405	12	3	772	0	9	2,272
Tennessee	762	177	46,749	0	0	102	0	0	0
West South Central	**840**	**615**	**206,678**	**9**	**8**	**2,556**	**0**	**314**	**86,830**
Arkansas	66	68	21,289	1	0	135	0	5	1,608
Louisiana	90	71	22,247	1	1	276	0	51	14,711
Oklahoma	96	85	27,683	0	0	27	0	39	9,440
Texas	588	391	135,459	7	7	2,118	0	219	60,871
Mountain	**520**	**650**	**208,691**	**2**	**1**	**696**	**0**	**17**	**5,196**
Arizona	133	117	35,582	0	0	154	0	6	1,769
Colorado	98	109	32,718	0	0	26	0	2	440
Idaho	0	0	0	0	0	0	0	0	0
Montana	29	61	19,002	0	0	23	0	0	26
Nevada	59	56	18,590	2	1	348	0	5	1,300
New Mexico	72	85	30,158	0	0	43	0	4	1,652
Utah	44	85	30,820	0	0	40	0	0	4
Wyoming	85	137	41,821	0	0	62	0	0	5
Pacific Contiguous	**64**	**43**	**10,291**	**16**	**28**	**8,518**	**0**	**121**	**29,856**
California	0	0	0	15	28	8,422	0	121	29,856
Oregon	2	2	534	0	0	5	0	0	0
Washington	62	41	9,757	1	0	91	0	0	0
Pacific Noncontiguous	**1**	**1**	**479**	**26**	**14**	**6,893**	**0**	**0**	**0**
Alaska	1	1	479	0	0	1	0	0	0
Hawaii	0	0	0	26	14	6,892	0	0	0
U.S. Total	**15,905**	**6,298**	**1,697,373**	**780**	**306**	**141,559**	**0**	**579**	**157,972**

Notes: •Totals may not equal sum of components because of independent rounding. •Data for 1989 are preliminary. •Data include petroleum coke. •These data are estimates derived from Form EIA-767, "Steam-Electric Plant Operation and Design Report", (See Appendix C for methodology).

Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Table 44. Number and Capacity of Coal-Fired Steam-Electric Generators for Plants with Environmental Equipment by Census Division and State, 1989

Census Division State	Generating Units[1]		Scrubbers		Particulate Collectors		Cooling Towers	
	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)
New England	**12**	**2,623**	**0**	**0**	**12**	**2,623**	**0**	**0**
Connecticut	1	400	0	0	1	400	0	0
Maine	0	0	0	0	0	0	0	0
Massachusetts	9	1,764	0	0	9	1,764	0	0
New Hampshire	2	459	0	0	2	459	0	0
Rhode Island	0	0	0	0	0	0	0	0
Vermont	0	0	0	0	0	0	0	0
Middle Atlantic	**94**	**24,669**	**16**	**5,512**	**94**	**24,669**	**20**	**12,657**
New Jersey	8	1,732	0	0	8	1,732	0	0
New York	25	3,743	1	655	25	3,743	0	0
Pennsylvania	61	19,194	15	4,857	61	19,194	20	12,657
East North Central	**306**	**81,341**	**17**	**7,216**	**309**	**81,486**	**46**	**20,979**
Illinois	55	17,123	4	1,439	55	17,123	3	671
Indiana	69	21,703	11	4,890	72	21,847	20	9,207
Michigan	55	12,659	0	0	55	12,659	7	536
Ohio	87	22,732	2	888	87	22,732	11	7,986
Wisconsin	40	7,126	0	0	40	7,126	5	2,579
West North Central	**140**	**35,924**	**27**	**11,539**	**140**	**35,924**	**49**	**12,914**
Iowa	31	5,857	1	160	31	5,857	9	1,912
Kansas	19	5,712	8	3,995	19	5,712	10	3,435
Minnesota	25	5,350	8	3,305	25	5,350	9	3,787
Missouri	38	11,517	3	1,099	38	11,517	12	1,019
Nebraska	14	3,038	0	0	14	3,038	4	429
North Dakota	12	3,994	7	2,981	12	3,994	5	2,332
South Dakota	1	456	0	0	1	456	0	0
South Atlantic	**206**	**65,840**	**13**	**6,752**	**204**	**65,778**	**66**	**34,796**
Delaware	6	1,034	0	0	6	1,034	1	442
District of Columbia	0	0	0	0	0	0	0	0
Florida	27	10,658	7	3,883	27	10,658	13	6,261
Georgia	38	12,957	0	0	38	12,957	12	8,862
Maryland	14	4,257	0	0	14	4,257	1	685
North Carolina	40	12,101	0	0	38	12,039	8	3,188
South Carolina	24	5,324	4	1,501	24	5,324	14	4,139
Virginia	24	4,549	0	0	24	4,549	3	713
West Virginia	33	14,958	2	1,368	33	14,958	14	10,506
East South Central	**135**	**39,326**	**22**	**7,873**	**135**	**39,326**	**33**	**15,408**
Alabama	39	11,943	4	1,591	39	11,943	6	3,535
Kentucky	53	15,212	16	5,882	53	15,212	23	10,724
Mississippi	6	2,150	2	400	6	2,150	4	1,150
Tennessee	37	10,020	0	0	37	10,020	0	0
West South Central	**54**	**32,458**	**15**	**9,891**	**54**	**32,458**	**30**	**17,746**
Arkansas	5	3,958	0	0	5	3,958	4	3,400
Louisiana	6	3,572	1	721	6	3,572	4	2,454
Oklahoma	10	5,210	1	520	10	5,210	8	4,072
Texas	33	19,719	13	8,650	33	19,719	14	7,820
Mountain	**89**	**30,383**	**47**	**20,063**	**85**	**28,604**	**78**	**26,736**
Arizona	13	5,297	8	2,425	13	5,297	11	4,804
Colorado	26	4,946	4	1,594	26	4,946	24	4,524
Idaho	NA	NA	NA	NA	NA	NA	NA	NA
Montana	5	2,464	4	2,273	5	2,464	4	2,273
Nevada	8	2,769	5	879	8	2,769	8	2,769
New Mexico	10	4,282	10	4,282	6	2,503	5	2,012
Utah	12	4,787	7	3,969	12	4,787	12	4,787
Wyoming	15	5,838	9	4,641	15	5,838	14	5,476
Pacific Contiguous	**3**	**2,020**	**0**	**0**	**3**	**2,020**	**2**	**1,460**
California	0	0	0	0	0	0	0	0
Oregon	1	561	0	0	1	561	0	0
Washington	2	1,460	0	0	2	1,460	2	1,460
Pacific Noncontiguous	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Alaska	0	0	0	0	0	0	0	0
Hawaii	0	0	0	0	0	0	0	0
U.S. Total	**1,039**	**314,585**	**157**	**68,846**	**1,036**	**312,887**	**324**	**142,696**

[1] Components are not additive since some generators are included in more than one category and not all units have environmental equipment.
[2] Nameplate capacity.
NA = Not applicable.
Notes: •Totals may not equal sum of components because of independent rounding. •These data are only for plants with a fossil-fueled steam-electric capacity of 100 or more megawatts. •Data for 1989 are preliminary. •Data include petroleum coke.
Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Table 45. Number and Capacity of Petroleum- and Gas-Fired Steam-Electric Generators for Plants with Environmental Equipment by Census Division and State, 1989

Census Division State	Generating Units[1]		Scrubbers		Particulate Collectors		Cooling Towers	
	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)	Number of Generators	Capacity[2] (megawatts)
New England	**44**	**7,459**	**0**	**0**	**43**	**7,044**	**1**	**415**
Connecticut	17	2,803	0	0	16	2,389	1	415
Maine	9	993	0	0	9	993	0	0
Massachusetts	8	2,850	0	0	8	2,850	0	0
New Hampshire	4	564	0	0	4	564	0	0
Rhode Island	6	249	0	0	6	249	0	0
Vermont	0	0	0	0	0	0	0	0
Middle Atlantic	**57**	**13,552**	**0**	**0**	**54**	**11,716**	**4**	**2,012**
New Jersey	14	2,130	0	0	13	1,995	2	311
New York	31	7,841	0	0	31	7,841	0	0
Pennsylvania	12	3,581	0	0	10	1,880	2	1,701
East North Central	**15**	**2,315**	**0**	**0**	**9**	**730**	**3**	**1,441**
Illinois	1	210	0	0	0	0	1	210
Indiana	5	284	0	0	2	140	0	0
Michigan	6	1,743	0	0	4	512	2	1,231
Ohio	0	0	0	0	0	0	0	0
Wisconsin	3	78	0	0	3	78	0	0
West North Central	**20**	**1,690**	**0**	**0**	**6**	**204**	**17**	**1,547**
Iowa	1	19	0	0	1	19	0	0
Kansas	15	1,536	0	0	1	50	14	1,486
Minnesota	1	75	0	0	1	75	0	0
Missouri	3	61	0	0	3	61	3	61
Nebraska	0	0	0	0	0	0	0	0
North Dakota	0	0	0	0	0	0	0	0
South Dakota	0	0	0	0	0	0	0	0
South Atlantic	**67**	**16,745**	**3**	**65**	**49**	**12,843**	**20**	**4,946**
Delaware	7	662	3	65	4	511	3	151
District of Columbia	2	580	0	0	0	0	2	580
Florida	34	10,552	0	0	23	8,700	11	1,853
Georgia	0	0	0	0	0	0	0	0
Maryland	13	2,594	0	0	11	1,276	3	1,480
North Carolina	7	455	0	0	7	455	0	0
South Carolina	0	0	0	0	0	0	0	0
Virginia	4	1,902	0	0	4	1,902	1	882
West Virginia	0	0	0	0	0	0	0	0
East South Central	**10**	**846**	**0**	**0**	**1**	**147**	**9**	**699**
Alabama	0	0	0	0	0	0	0	0
Kentucky	1	147	0	0	1	147	0	0
Mississippi	9	699	0	0	0	0	9	699
Tennessee	0	0	0	0	0	0	0	0
West South Central	**105**	**15,938**	**0**	**0**	**5**	**2,452**	**103**	**14,780**
Arkansas	7	580	0	0	0	0	7	580
Louisiana	18	2,728	0	0	2	1,184	17	2,136
Oklahoma	19	4,350	0	0	1	567	18	3,783
Texas	61	8,281	0	0	2	701	61	8,281
Mountain	**43**	**3,120**	**0**	**0**	**2**	**101**	**43**	**3,120**
Arizona	20	1,597	0	0	0	0	20	1,597
Colorado	3	111	0	0	2	101	3	111
Idaho	NA	NA	NA	NA	NA	NA	NA	NA
Montana	0	0	0	0	0	0	0	0
Nevada	6	433	0	0	0	0	6	433
New Mexico	13	910	0	0	0	0	13	910
Utah	1	69	0	0	0	0	1	69
Wyoming	0	0	0	0	0	0	0	0
Pacific Contiguous	**33**	**3,705**	**0**	**0**	**6**	**527**	**31**	**3,379**
California	33	3,705	0	0	6	527	31	3,379
Oregon	0	0	0	0	0	0	0	0
Washington	0	0	0	0	0	0	0	0
Pacific Noncontiguous	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Alaska	0	0	0	0	0	0	0	0
Hawaii	0	0	0	0	0	0	0	0
U.S. Total	**394**	**65,370**	**3**	**65**	**175**	**35,764**	**231**	**32,337**

[1] Components are not additive since some generators are included in more than one category and not all units have environmental equipment.
[2] Nameplate capacity.
NA = Not applicable.
Notes: •Totals may not equal sum of components because of independent rounding. •These data are only for plants with a fossil-fueled steam-electric capacity of 100 or more megawatts. •Data for 1989 are preliminary. •Data include petroleum coke.
Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Table 46. Average Quality of Fossil Fuels Burned by Census Division and State, 1989 and 1988

Census Division State	Coal						Petroleum				Gas	
	1989[1]			1988[2]			1989[1]		1988[2]		1989[1]	1988
	Average Btu per Pound	Sulfur Percent by Weight	Ash Percent by Weight	Average Btu per Pound	Sulfur Percent by Weight	Ash Percent by Weight	Average Btu per Gallon	Sulfur Percent by Weight	Average Btu per Gallon	Sulfur Percent by Weight	Average Btu per Cubic Foot	Average Btu per Cubic Foot
New England	**13,061**	**1.28**	**7.6**	**13,120**	**1.30**	**7.5**	**150,346**	**1.35**	**150,175**	**1.31**	**1,044**	**1,032**
Connecticut	13,210	.55	6.1	13,249	.54	6.3	150,115	.88	150,267	.85	1,030	1,030
Maine	–	–	–	–	–	–	149,833	.89	149,774	.90	–	–
Massachusetts	12,983	1.21	8.0	13,073	1.19	7.9	149,845	1.64	149,483	1.58	1,045	1,032
New Hampshire	13,244	2.07	7.0	13,187	2.23	7.2	154,557	1.92	154,523	1.81	–	–
Rhode Island	–	–	–	–	–	–	150,747	1.00	150,684	.98	1,033	1,032
Vermont	–	–	–	–	–	–	140,000	.30	138,000	.30	1,000	–
Middle Atlantic	**12,438**	**1.91**	**12.4**	**12,460**	**2.01**	**12.6**	**149,147**	**.64**	**148,791**	**.65**	**1,032**	**1,028**
New Jersey	13,148	1.15	7.8	13,279	1.25	8.1	148,274	.43	145,994	.40	1,033	1,032
New York	12,765	1.70	9.6	12,733	1.71	9.9	149,225	.73	149,133	.75	1,031	1,027
Pennsylvania	12,305	2.03	13.4	12,346	2.13	13.4	149,416	.30	149,140	.31	1,031	1,029
East North Central	**10,995**	**1.87**	**9.2**	**11,081**	**1.88**	**9.1**	**145,265**	**.66**	**146,390**	**.66**	**939**	**967**
Illinois	10,678	2.05	8.8	10,662	2.03	8.6	148,086	.53	148,896	.61	1,016	1,021
Indiana	10,652	2.26	9.2	10,763	2.36	9.2	136,987	.33	137,454	.29	921	927
Michigan	11,236	.69	7.1	11,440	.72	7.0	144,174	.75	145,967	.77	1,019	1,021
Ohio	11,798	2.48	11.7	11,871	2.46	11.5	146,599	.81	145,147	.64	1,019	1,028
Wisconsin	9,630	.85	6.6	9,689	.89	6.6	137,569	.38	137,487	.32	1,005	993
West North Central	**8,677**	**1.03**	**7.4**	**8,683**	**1.06**	**7.8**	**142,351**	**.82**	**143,145**	**1.02**	**985**	**1,000**
Iowa	8,935	.76	5.9	9,163	.82	6.1	137,886	.43	137,474	.42	1,006	1,004
Kansas	8,842	.68	6.4	8,921	.74	6.5	144,284	.72	141,906	.97	980	998
Minnesota	8,703	.56	7.3	8,660	.62	8.0	139,948	.40	135,527	.30	1,003	1,003
Missouri	10,365	2.18	8.8	10,410	2.23	9.0	142,979	1.27	145,839	1.32	1,015	992
Nebraska	8,672	.36	5.2	8,585	.36	5.0	147,709	1.09	147,388	1.21	958	1,003
North Dakota	6,589	.73	8.4	6,558	.71	9.3	138,355	.41	138,912	.48	1,050	1,065
South Dakota	6,360	.84	7.6	6,515	.85	7.9	138,050	.38	135,970	.30	996	1,002
South Atlantic	**12,357**	**1.49**	**10.0**	**12,403**	**1.52**	**10.1**	**150,407**	**1.15**	**150,654**	**1.13**	**1,017**	**1,012**
Delaware	12,940	1.03	9.0	13,074	1.51	9.1	150,014	1.13	150,448	1.12	1,105	1,071
District of Columbia	–	–	–	–	–	–	143,353	.91	143,650	.94	–	–
Florida	12,252	1.75	8.6	12,250	1.77	8.7	151,208	1.23	151,491	1.18	1,011	1,008
Georgia	12,054	1.66	10.1	12,111	1.74	10.2	140,246	.87	144,173	1.47	1,011	1,023
Maryland	12,641	1.43	10.7	12,666	1.43	11.0	149,801	1.29	149,333	1.29	1,046	1,042
North Carolina	12,555	.92	9.8	12,604	.92	9.8	138,530	.20	138,728	.20	–	–
South Carolina	12,587	1.13	9.2	12,646	1.18	9.5	139,499	1.43	138,514	.54	1,023	1,032
Virginia	12,705	.92	9.3	12,804	.92	9.4	148,704	.81	147,058	.83	1,042	1,054
West Virginia	12,347	1.83	11.7	12,418	1.76	11.7	139,312	.35	139,571	.14	1,000	1,000
East South Central	**11,865**	**2.01**	**10.6**	**11,956**	**1.93**	**10.4**	**146,229**	**1.96**	**145,902**	**1.92**	**1,025**	**1,026**
Alabama	11,993	1.62	11.9	12,159	1.47	11.9	135,972	.25	136,477	.20	1,027	1,031
Kentucky	11,698	2.33	10.6	11,723	2.20	10.6	138,697	.26	138,657	.30	1,011	1,023
Mississippi	12,634	1.55	7.8	12,562	1.40	7.6	149,992	2.71	149,754	2.71	1,025	1,026
Tennessee	11,828	2.06	9.6	11,986	2.08	9.6	138,175	.30	138,242	.28	–	–
West South Central	**8,751**	**.42**	**6.1**	**8,475**	**.43**	**6.1**	**145,730**	**.64**	**145,220**	**.66**	**1,037**	**1,041**
Arkansas	8,628	.33	5.0	8,550	.34	5.4	148,574	.72	143,983	.63	1,016	1,029
Louisiana	8,837	.50	7.8	7,961	.51	7.7	144,956	.61	146,168	.68	1,033	1,044
Oklahoma	8,777	.43	5.5	8,847	.43	5.3	140,062	.51	138,765	.52	1,047	1,038
Texas	7,229	.74	12.2	7,248	.70	12.2	142,833	.54	144,556	.56	1,033	1,034
Mountain	**9,859**	**.56**	**11.2**	**9,829**	**.56**	**10.9**	**143,753**	**.62**	**143,284**	**.65**	**1,028**	**1,020**
Arizona	10,591	.50	11.4	10,663	.51	11.1	143,649	.53	139,328	.30	1,036	1,034
Colorado	9,861	.37	6.9	9,792	.41	7.0	136,950	.34	138,812	.53	952	963
Idaho	–	–	–	–	–	–	–	–	–	–	–	–
Montana	8,513	.66	9.5	8,522	.67	9.4	136,865	.50	118,412	.42	1,317	1,208
Nevada	11,877	.52	9.3	11,963	.50	9.3	147,363	.77	147,611	.69	1,032	1,031
New Mexico	9,213	.84	21.7	9,092	.81	21.4	136,052	.83	138,732	1.87	1,036	1,028
Utah	11,406	.49	11.3	11,592	.50	10.7	138,328	.24	138,722	.47	875	–
Wyoming	8,785	.53	8.0	8,709	.53	7.9	139,357	.30	139,509	.32	1,000	1,000
Pacific Contiguous	**8,083**	**.63**	**13.1**	**8,179**	**.64**	**13.9**	**146,166**	**.30**	**146,993**	**.34**	**1,039**	**1,035**
California	–	–	–	–	–	–	146,223	.29	147,000	.34	1,039	1,035
Oregon	7,977	.31	4.5	–	–	–	136,800	.05	–	–	–	–
Washington	8,088	.65	13.6	8,179	.64	13.9	141,447	1.55	141,000	.30	–	–
Pacific Noncontiguous	**7,909**	**.15**	**8.2**	**7,819**	**.14**	**8.7**	**148,935**	**.64**	**149,387**	**.62**	**–**	**–**
Alaska	7,909	.15	8.2	7,819	.14	8.7	134,283	.20	–	–	–	–
Hawaii	–	–	–	–	–	–	148,937	.64	149,387	.62	–	–
U.S. Average	**10,428**	**1.33**	**10.0**	**10,459**	**1.34**	**9.9**	**149,260**	**.93**	**149,309**	**.93**	**1,030**	**1,032**

[1] Data for 1989 are preliminary.
[2] Data for 1988 are revised. See Appendix C for an explanation.
Notes: •Totals may not equal sum of components because of independent rounding. •Data include petroleum coke.
Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Table 47. Average Flue Gas Desulfurization Costs by Census Division and State, 1986-1989

Census Division and State	Average O&M Costs (Mills per Kilowatthour)				Average Installed Cost (Dollars per Kilowatt)			
	1989[1]	1988	1987	1986	1989[1]	1988	1987	1986
New England	–	–	–	–	–	–	–	–
Connecticut	–	–	–	–	–	–	–	–
Maine	–	–	–	–	–	–	–	–
Massachusetts	–	–	–	–	–	–	–	–
New Hampshire	–	–	–	–	–	–	–	–
Rhode Island	–	–	–	–	–	–	–	–
Vermont	–	–	–	–	–	–	–	–
Middle Atlantic	4.92	4.15	4.78	5.19	175	176	175	183
New Jersey	–	–	–	–	–	–	–	–
New York	1.24	1.23	1.28	1.33	223	223	223	223
Pennsylvania	5.90	4.83	5.66	6.10	168	170	168	177
East North Central	2.41	2.36	2.49	2.65	137	139	139	139
Illinois	2.69	2.64	2.50	2.72	146	146	145	145
Indiana	2.26	2.26	2.36	2.39	153	157	157	157
Michigan	–	–	–	–	–	–	–	–
Ohio	2.76	2.39	3.58	4.44	47	47	47	47
Wisconsin	–	–	–	–	–	–	–	–
West North Central	.73	.80	.86	.68	74	72	71	71
Iowa	2.30	2.03	2.36	2.57	222	222	153	153
Kansas	.59	.59	.29	.18	71	72	71	71
Minnesota	.26	.30	.38	.40	74	70	70	70
Missouri	2.05	1.78	2.36	2.01	89	89	82	82
Nebraska	–	–	–	–	–	–	–	–
North Dakota	.91	1.13	.98	.77	65	59	59	59
South Dakota	–	–	–	–	–	–	–	–
South Atlantic	1.47	1.96	1.63	1.79	92	93	92	111
Delaware[2]	30.80	35.81	25.61	23.50	1,385	1,385	1,385	1,385
District of Columbia	–	–	–	–	–	–	–	–
Florida	.94	1.60	1.20	1.28	81	81	81	126
Georgia	–	–	–	–	–	–	–	–
Maryland	–	–	–	–	–	–	–	–
North Carolina	–	–	–	–	–	–	–	–
South Carolina	.61	.59	.59	.87	46	46	46	46
Virginia	–	–	–	–	–	–	–	–
West Virginia	2.11	2.14	1.91	1.78	111	111	110	98
East South Central	1.48	1.66	1.61	1.66	123	122	121	121
Alabama	.76	1.58	1.13	1.30	82	82	82	82
Kentucky	1.73	1.75	1.81	1.86	137	137	137	137
Mississippi	.33	.29	.40	.27	70	70	70	70
Tennessee	–	–	–	–	–	–	–	–
West South Central	.99	.93	1.08	1.04	70	69	72	72
Arkansas	–	–	–	–	–	–	–	–
Louisiana	–	.13	.11	12	75	75	75	75
Oklahoma	.54	.57	1.29	.64	92	92	92	92
Texas	1.03	1.03	1.15	1.14	68	67	70	70
Mountain	.71	.74	.89	.99	152	152	153	152
Arizona	.71	1.05	1.03	1.29	141	141	123	123
Colorado	.49	.49	.56	.44	85	85	85	85
Idaho	–	–	–	–	–	–	–	–
Montana	1.04	.80	1.34	1.02	274	274	274	274
Nevada	1.51	1.80	1.68	4.45	126	126	126	120
New Mexico	.91	1.04	1.35	1.32	192	192	192	192
Utah	.52	.49	.64	.75	97	97	89	72
Wyoming	.56	.62	.49	.62	137	137	137	137
Pacific Contiguous	–	–	–	–	–	–	–	–
California	–	–	–	–	–	–	–	–
Oregon	–	–	–	–	–	–	–	–
Washington	–	–	–	–	–	–	–	–
Pacific Noncontiguous	–	–	–	–	–	–	–	–
Alaska	–	–	–	–	–	–	–	–
Hawaii	–	–	–	–	–	–	–	–
U.S. Average	1.34	1.35	1.50	1.61	119	119	119	121

[1] Data for 1989 are preliminary.

[2] The high cost shown for Delaware is attributable to the flue gas desulfurization (FGD) units belonging to a plant that provides steam for sale and steam used to produce electricity. The FGD costs include the costs incurred in the production of steam for sale.

O&M = Operation and Maintenance

Notes: •Totals may not equal sum of components because of independent rounding. •Data include petroleum coke. •A mill is a monetary cost and billing unit equal to 1/1000 of the U.S. dollar (equivalent to 1/10 of 1 cent).

Source: Energy Information Administration, Form EIA-767, "Steam-Electric Plant Operation and Design Report."

Electric Power Transactions

This chapter provides summary information for the electric utility industry on its operations and wholesale electricity trade at the international (Canada and Mexico), national, and North American Electric Reliability Council (NERC) region levels. The NERC is an organization established by the electric utility industry for maintaining, coordinating, and promoting reliability among the interconnected systems of North America.

Background

An electric power system is a group of generation, transmission, distribution, communication, and other facilities that are physically connected and operated as a single unit under one control (Figure 23). Transmission and distribution lines and associated facilities are used to transmit electricity from its point of origin (the generator) to the ultimate consumer. Although, due to its physical characteristics, electricity flows along all available paths, it follows the path of least resistance. The flow of electricity must be closely monitored to ensure that a sufficient quantity is available to satisfy all demand (load) for electricity placed on the power system. In addition, the flow is maintained at a frequency of 60 hertz per second.

The flow of electricity within the system is maintained and monitored by dispatch centers. The dispatch center must inventory and prioritize all generating capacity available to it, track transactions involving the buying or selling of either electric power or capacity, monitor current load, and anticipate future load on the system. It is the responsibility of the dispatch center to match the supply of electricity with its demand. The demand for electricity is not constant in nature. That is, load requirements fluctuate continuously, based on such factors as time of day, season of the year, and the characteristics of territory served by the system. Nonetheless, the dispatch center must be ready to meet the highest level of load placed on the system. The dispatch center must accommodate the loss of generating facilities (both when planned and when unexpected). In addition, the center must monitor transmission lines to determine whether the flow of electricity is approaching the carrying limits of the lines. In order to carry out its responsibilities in a timely fashion, the dispatch center is authorized to buy and sell electricity based on system requirements.

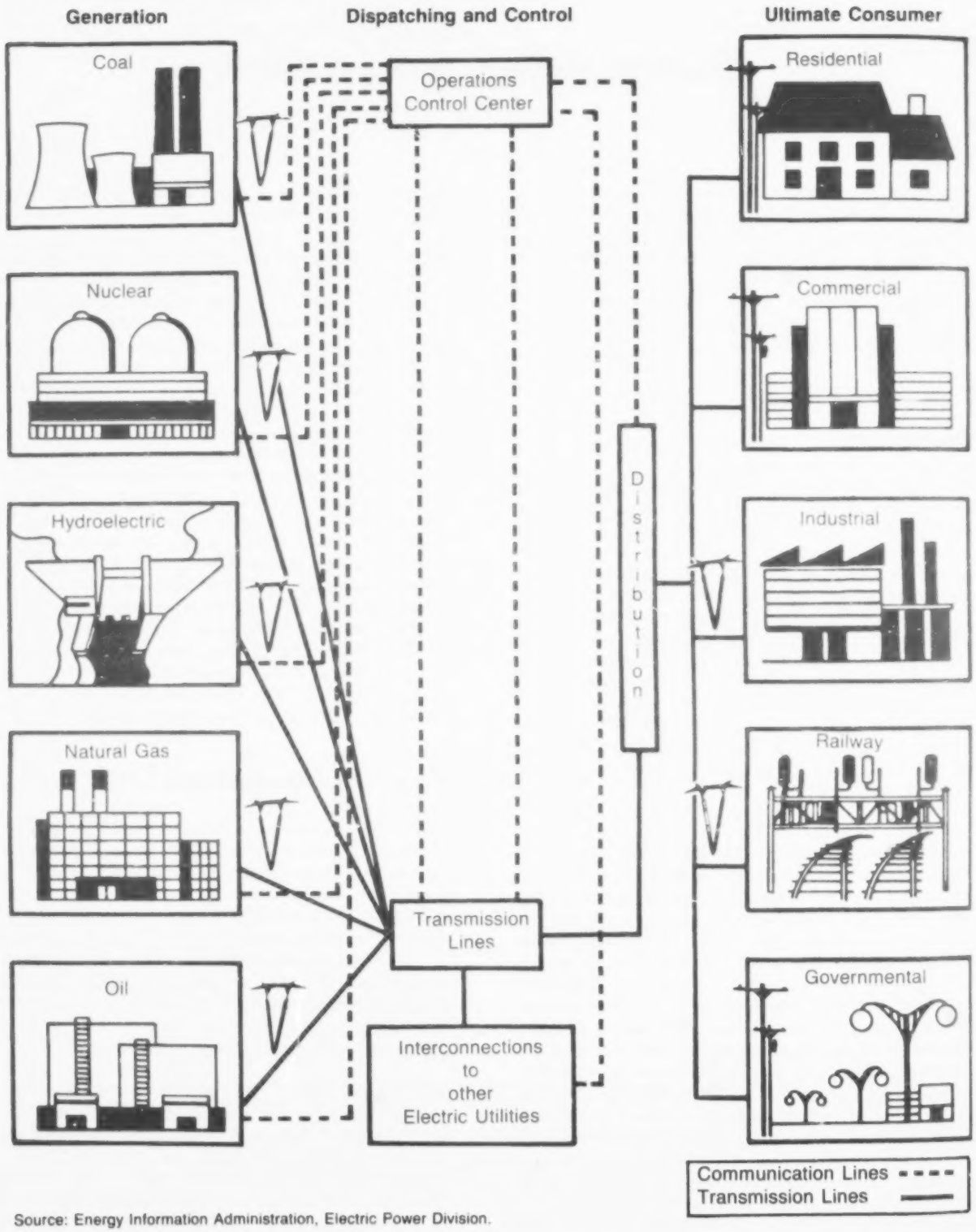
Authority for these transactions has been preapproved under interconnection agreements (contracts) that have been signed by all the electric utilities that are physically interconnected. These transactions include purchases, sales for resale, exchanges, and wheeling of energy. Purchase transactions involve buying power among electric utilities and nonutility producers of electricity. Sales for resale transactions refer to power sold by one electric utility to other utilities for distribution. Some transactions involving the trade of electric energy are based on the availability of excess generating capacity or the diversity in load requirements. For example, if one electric utility has its lowest load during the winter season, it may arrange to offer its available excess generating capacity in exchange for excess generating capacity available at a facility with low summer load. This type of arrangement is an exchange transaction. However, the repayment or replacement of exchange energy may extend over several years. Wheeling transactions are the movement of electricity from one utility to another utility over the transmission facilities of the intervening utilities.

Power Pool Transactions

In addition to dealing in one-time purchase and sale transactions, many electric utilities have joined together and formed power pools to achieve better operating efficiencies and to gain additional support for maintaining a functional electrical system. Thus, they share the benefits achieved by joint planning, coordinated use of generating and transmission facilities, and/or coverage of facility outages. This coordination also provides the opportunity to manage short-term saving, much of it coming from varying fuel prices and the costs associated with different mixes of capacity.

Power pools can be made up of two electric utilities, like the Michigan Electric Coordinated System (Detroit Edison Company and Consumer Power Company), include all the major investor-owned utilities within a State (the New York Power Pool), or cross State lines (the PJM Power Pool includes parts or all of Pennsylvania, New Jersey, Maryland, and Delaware).

Figure 23. An Integrated Electric Utility System



Source: Energy Information Administration, Electric Power Division.

Power pools may run under a single-system dispatch to meet combined-load requirements and maintenance programs, or just share the benefits of planned or hourly wholesale sales of power and energy among the member utilities. Power pools may have responsibility for coordinating flow within the geographic area of the interconnected systems. In any case, they are bound by the operating standards established by the electric power industry. These standards require the coordination and maintenance of system stability and reliable service on a regional basis.

NERC Profile

The North American Electric Reliability Council (NERC) was formed in 1968 during the aftermath of the Northeast Blackout on November 9, 1965, and became incorporated in 1975 (Figure 24). The NERC consists of nine regional reliability councils whose memberships comprise essentially all of the electric utility systems in the contiguous United States, Canada, and Baja California Norte, Mexico. The NERC also has one affiliate member, the Alaska Systems Coordinating Council. The regional councils are responsible for maintaining the three power grids (the Seven Interconnected Regions Power Grid or the Eastern Power Grid, the Western Power Grid, and the Electric Reliability Council of Texas Power Grid) present in the contiguous United States. The data for NERC regions in this publication are based upon the assignment of all electric utilities to an individual region and are for the U.S. portion of the regions only.

Figure 24. North American Electric Reliability Council Region Map for the United States

Regional Electric Reliability Council Areas:

ECAR—East Central Area Reliability Coordination Agreement
MAIN—Mid-American Interpool Network
MAAC—Mid-Atlantic Area Council
MAPP (U.S.)—Mid-Continent Area Power Pool
NPCC (U.S.)—Northeast Power Coordinating Council
SERC—Southeastern Electric Reliability Council
SPP—Southwest Power Pool
ERCOT—Electric Reliability Council of Texas
WSCC (U.S.)—Western Systems Coordinating Council

Source: North American Electric Reliability Council

Electric Utility Transactions

Electric utility transactions *(wholesale electricity trade)* include purchases, sales for resale, exchanges, and the transmission of electricity. These transactions allow electric utilities to share resources and to provide mutual assistance in time of potential and actual need. They allow the utility systems to provide lower cost service to their consumers by taking advantage of the load diversity of each utility. These transactions also allow each utility to conserve its own resources, to share the benefits of reduced operating costs with its consumers, to receive emergency energy support from other utilities, and to reduce the cost of its own requirements for operating reserve. However, due to the complexity of electric power transactions involving the specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, the reporting of both the classification and quantity of each transaction among utilities may not be consistent.

Electric utilities originally became interested in energy transactions because of the savings gained from reduced or avoided production costs. An electric utility can avoid building expensive additional capacity if the electricity can be obtained from other sources. Purchasing power from other utilities can help a utility meet peak load without using expensive oil- or gas-fired turbines. Similarly, a utility benefits from being able to delay or stagger construction of additional baseload plants. Electric utilities can also delay new plant construction by purchasing electricity from nonutility generators under long-term contracts.

Regulation of Electric Utility Transactions

The Federal Energy Regulatory Commission (FERC) is responsible for regulating wholesale transactions. Electric utilities file with the FERC for approval of proposed rate schedules for transmission services and charges, and for wholesale transactions. Transmission filings cover the allocation of electric power flows on the transmission line systems. These filings cover *firm-carrying* capacity, *interruptible-carrying* capacity, and *third-party-transfer* capacity. Other categories of filings usually cover the responsibilities of the utilities to one another during normal and emergency conditions, operating-reserves support, diversity exchanges, and unscheduled or inadvertent-energy flows.

Wholesale transactions include *capacity* sales, *energy* sales, and *energy exchanges*. Wholesale transactions are further divided by duration of the sale and the type of capacity and energy sold. The length of the sale can be for an hour, a day, a week, a month (or several months), a season, several years, or some combination of these time periods.

Capacity sales are usually considered *firm* sales (that is, associated energy may be taken, or the capacity must be paid for if the energy is not taken; and the delivery is scheduled during normal system operating conditions). This capacity may be made available from the entire system or from an identified generating unit. The capacity offered in these transactions may be available only during a set period of seasonal diversity, an off-peak time of the day, or from a generator, which is currently not fully utilized, that is fired by a particular fuel. The energy associated with this capacity sale, if required, has a separate cost schedule from the capacity charge attached to each kilowatt of power.

Nonfirm sales, sometimes called energy, economy, or interruptible sales, do not have a demand or capacity charge included in the price of the transaction. These transactions are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions. The sales are often based on splitting the benefits gained by the parties involved. They are used to gain operational savings, such as avoiding the use of more expensive fuels, and selling electricity generated by the spillage of excess reservoir water.

Energy exchanges involve transfers of energy to other systems at no monetary charge. The energy must be returned in kind at a later date agreed upon by both parties. Otherwise, the receiving party pays for the energy received. The incidental miscellaneous transfer of energy and inadvertent flow are also handled in the same manner. In total, these wholesale transactions have become very important tools used by the U.S. electric utility industry to reduce costs and avoid expensive new capacity.

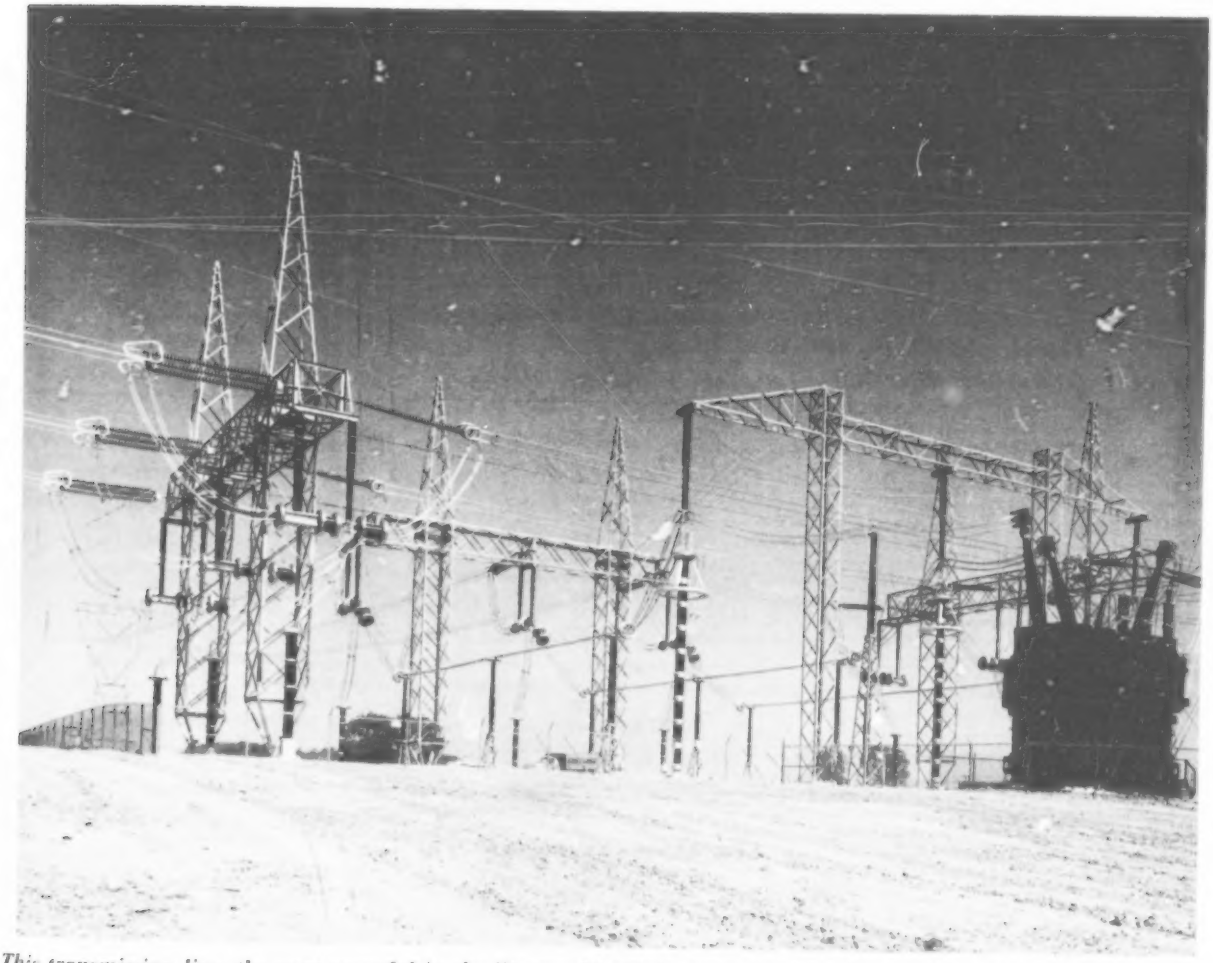
International Transactions

U.S. utilities have also taken advantage of being able to enter into international trade agreements to acquire energy from Canada and Mexico. These trade agreements between utilities cover a variety of transaction options. These options include purchasing nonfirm energy from relatively inexpensive renewable resources (hydroelectric from Canada and geothermal from Mexico); acquiring additional generating capability to support the requirements for supply at U.S. electric utilities; the holding of purchased electricity (as reservoir water) to be reacquired when needed by U.S. electric utilities; and sharing the benefits of coordinated operations planning for the systems. In some instances, consumers can be served more efficiently if they are connected to foreign transmission lines, because they are geographically closer to those lines.

Data Sources

Statistics on electricity transactions among electric utilities and on international electricity trade (including the United States, Canada, and Mexico) are presented in the following tables. These data were obtained from the Form EIA-861, "The Annual Electric Utility Report"; the Form EIA-860, "Annual Electric Generator Report"; the Department of Energy, Office of the Assistant Secretary for International Affairs and Energy Emergencies, Form IE-411, "Coordinated Bulk Power Supply Program"; and the Department of Energy, Office of the Assistant Secretary for Fossil Energy, Form FE-781R, "Annual Report of International Electric Import/Export Data." More detailed information on electric power transactions is published in the *Electric Trade in the United States*.[1]

[1]Energy Information Administration, *Electric Trade in the United States*, DOE/EIA-0531(86)(Washington, DC, June 1990).



This transmission line, the most powerful in the Western World, is cosponsored by the American Electric Power System and Westinghouse Electric Corporation.

Table 48. Energy Account Balance of Electricity, 1987-1989
(Million Kilowatthours)

Item	1989[1]	1988	1987
Source			
Net Generation	2,811,398	2,730,774	2,632,019
Purchases from Utilities	959,375	922,038	870,345
Purchases from Nonutilities	89,813	68,030	50,165
Net Exchange	[2] 2,369	32,955	45,619
Net Wheeling	3,525	2,262	2,019
Disposition			
Sales to Ultimate Consumers	2,646,809	2,578,062	2,457,272
Sales for Resale	975,676	945,993	916,703
Energy Furnished Without Charge	5,647	5,525	5,149
Energy Used by Utility Electric Department	19,501	16,962	16,965
Energy Losses[3]	218,846	209,516	199,861

[1] Data for 1989 are preliminary.
[2] The shift in magnitude for net exchange reflects a change in accounting procedures by electric utilities because of reclassification of various transactions for bulk trade. In addition, the Tennessee Valley Authority reduced their net exchanges by 15 billion kilowatthours from 1988.
[3] These values are not measured; however, they represent losses and unaccounted for energy. These values are calculated in order that source and disposition of energy are equivalent.

Notes: •Annual net generation data shown here should only be used in comparison with other Form EIA-861 data. Total annual net generation data are published by the Energy Information Administration from its Form EIA-759, "Monthly Power Plant Report," (Table 1). •Totals may not equal sum of components because of independent rounding. •Source and disposition are the aggregation of data reported for each utility. Source and disposition of energy are not additive due to double counting. Purchases from utilities, net exchange and net wheeling (except for imports) are included in net generation. Sales for resale is included in sales to ultimate consumers. •Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 49. Net Generation by North American Electric Reliability Council Region, Alaska, and Hawaii, 1987-1989
(Million Kilowatthours)

North American Electric Reliability Council Region, Alaska, and Hawaii	1989[1]	1988	1987
ECAR	487,659	487,040	463,569
ERCOT	185,011	179,442	173,645
MAAC	193,889	191,874	185,541
MAIN	200,660	198,666	185,240
MAPP(U.S.)	116,410	118,238	122,381
NPCC(U.S.)	233,624	223,996	212,165
SERC	612,643	571,541	559,700
SPP	239,032	233,396	231,865
WSCC(U.S.)	530,205	514,622	496,398
Contiguous U.S.	**2,799,130**	**2,718,815**	**2,620,505**
Alaska	4,575	4,460	4,412
Hawaii	7,692	7,499	7,103
U.S. Total	**2,811,398**	**2,730,774**	**2,632,019**

[1] Data for 1989 are preliminary.

Notes: •Annual net generation data shown here should only be used in comparison with other Form EIA-861 data. Total annual net generation data are published by the Energy Information Administration from its Form EIA-759, "Monthly Power Plant Report," (Table 1). •Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 50. Sales to Ultimate Consumers by Sector, North American Electric Reliability Council Region, Alaska, and Hawaii, 1987-1989

(Million Kilowatthours)

North American Electric Reliability Council Region, Alaska, and Hawaii	Total	Residential	Commercial	Industrial	Other[1]
			1989[2]		
ECAR	414,977	126,538	91,610	187,166	9,663
ERCOT	195,648	70,005	52,988	67,783	4,872
MAAC	207,325	70,756	62,117	71,649	2,803
MAIN	188,425	56,318	52,258	71,518	8,330
MAPP(U.S.)	113,692	42,050	23,584	44,531	3,528
NPCC(U.S.)	233,573	76,090	84,682	58,986	13,815
SERC	571,569	225,987	146,375	182,469	16,739
SPP	223,134	77,907	57,480	79,450	8,298
WSCC(U.S.)	486,675	156,102	150,856	158,203	21,515
Contiguous U.S.	**2,635,019**	**901,752**	**721,950**	**921,754**	**89,562**
Alaska	4,142	1,643	1,897	450	151
Hawaii[3]	7,649	2,129	2,014	3,454	52
U.S. Total	**2,646,809**	**905,525**	**725,861**	**925,659**	**89,765**
			1988		
ECAR	408,171	128,073	89,404	181,082	9,611
ERCOT	192,367	68,708	51,723	67,182	4,755
MAAC	202,705	69,794	60,669	69,511	2,730
MAIN	185,430	58,202	51,470	67,344	8,414
MAPP(U.S.)	113,136	42,616	23,479	43,596	3,445
NPCC(U.S.)	228,883	74,897	83,030	57,527	13,429
SERC	545,250	217,201	135,410	176,737	15,901
SPP	218,281	76,942	56,183	76,625	8,530
WSCC(U.S.)	472,386	152,798	144,022	152,975	22,592
Contiguous U.S.	**2,566,607**	**889,231**	**695,390**	**892,579**	**89,407**
Alaska	4,045	1,590	1,778	542	136
Hawaii[3]	7,411	2,045	1,932	3,378	56
U.S. Total	**2,578,062**	**892,866**	**699,100**	**896,498**	**89,598**
			1987		
ECAR	389,793	121,657	83,615	175,264	9,264
ERCOT	184,494	65,635	49,257	65,117	4,485
MAAC	191,677	65,279	56,758	66,946	2,694
MAIN	176,801	54,993	48,813	64,889	8,108
MAPP(U.S.)	104,687	39,632	22,106	39,739	3,210
NPCC(U.S.)	216,979	70,366	78,376	55,339	12,898
SERC	522,900	210,117	128,363	169,068	15,352
SPP	211,806	75,212	53,554	74,363	8,677
WSCC(U.S.)	447,158	144,006	136,053	143,803	23,296
Contiguous U.S.	**2,446,302**	**846,897**	**656,894**	**854,527**	**87,983**
Alaska	3,943	1,540	1,729	516	157
Hawaii[3]	7,028	1,973	1,810	3,189	56
U.S. Total	**2,457,272**	**850,410**	**660,433**	**858,233**	**88,196**

[1] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.
[2] Data for 1989 are preliminary.
[3] Hawaii includes nonutility transactions only.
Note: Totals may not equal sum of components because of independent rounding.
Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

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Table 51. Generating Capability by North American Electric Reliability Council Region, Alaska, and Hawaii, as of December 1987-1989
(Megawatts)

North American Electric Reliability Council Region, Alaska, and Hawaii	1989	1988	1987
ECAR	102,545	101,257	101,337
ERCOT	49,733	48,928	45,835
MAAC	50,071	48,766	48,744
MAIN	49,511	49,631	49,228
MAPP(U.S.)	30,376	30,348	32,718
NPCC(U.S.)	54,460	54,067	53,731
SERC	145,129	142,404	141,430
SPP	70,468	70,311	70,158
WSCC(U.S.)	129,296	128,986	128,112
Contiguous U.S.	**681,589**	**674,697**	**671,293**
Alaska	1,546	1,504	1,490
Hawaii	1,483	1,453	1,361
U.S. Total	**684,619**	**677,654**	**674,144**

Notes: •Totals may not equal sum of components because of independent rounding. •Generating capability is net summer capability.
Source: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Table 52. Noncoincidental Peak Load by North American Electric Reliability Council Region, Alaska, and Hawaii, 1987-1989
(Megawatts)

North American Electric Reliability Council Region, Alaska, and Hawaii	1989		1988		1987	
	Summer	Winter	Summer	Winter	Summer	Winter
ECAR	75,442	73,080	79,149	67,771	72,561	68,118
ERCOT	40,402	38,388	40,843	34,621	39,339	31,399
MACC	41,614	38,161	43,110	36,363	40,526	35,775
MAIN	39,460	33,770	41,139	30,631	37,446	30,606
MAPP(U.S.)	23,531	20,699	24,899	20,162	23,162	19,335
NPCC(U.S.)	45,031	42,588	45,245	42,951	42,651	41,902
SERC	117,051	121,995	115,168	108,649	109,798	105,476
SPP	49,439	42,268	49,356	35,649	47,723	34,472
WSCC(U.S.)	90,657	84,768	90,551	82,937	82,967	81,182
Contiguous U.S.	**522,627**	**495,717**	**529,460**	**459,734**	**496,173**	**448,265**
Alaska	455	626	[1]	[1]	[1]	[1]
Hawaii	[1]	[1]	[1]	[1]	[1]	[1]
U.S. Total	**523,082**	**496,343**	**529,460**	**459,734**	**496,173**	**448,265**

[1] Data for Alaska were first submitted in 1989; data for Hawaii are not submitted for this form.
Note: Noncoincidental peak load is the sum of utility peak loads that may occur at the same time.
Source: Department of Energy, Office of the Assistant Secretary for International Affairs and Energy Emergencies, Form IE-411, "Coordinated Bulk Power Supply Program."

Table 53. Utility Receipts by North American Electric Reliability Council Region, Alaska, and Hawaii, 1987-1989

(Million Kilowatthours)

North American Electric Reliability Council Region, Alaska, and Hawaii	Total Receipts[1]			Purchased Power			Exchange Received			Wheeling Received		
	1989[2]	1988	1987	1989[2]	1988	1987	1989[2]	1988	1987	1989[2]	1988	1987
ECAR	206,000	186,112	161,099	90,953	95,143	84,289	93,949	75,848	66,463	21,098	15,121	10,347
ERCOT	102,501	101,642	96,724	58,354	58,629	54,710	34,733	35,153	35,482	9,414	7,861	6,532
MAAC	86,267	76,386	70,874	46,371	41,173	32,381	31,511	27,731	31,827	8,385	7,482	6,665
MAIN	63,790	58,756	56,675	33,699	29,756	28,251	26,877	27,086	26,353	1,215	1,915	2,071
MAPP(U.S.)	114,246	114,754	105,209	68,948	68,937	62,757	36,090	38,014	35,078	3,208	7,804	7,374
NPCC(U.S.)	183,999	178,664	159,536	125,993	122,867	121,912	15,109	17,432	17,139	42,897	38,365	20,486
SERC	383,664	348,524	339,525	278,755	256,746	243,312	82,183	79,424	85,174	22,726	12,354	11,039
SPP	140,237	130,316	116,128	107,120	102,211	89,680	13,526	8,015	16,292	19,591	20,089	10,156
WSCC(U.S.)	485,872	443,345	405,057	276,294	211,960	200,590	84,754	73,630	65,441	164,824	157,755	118,925
Contiguous U.S.	**1,766,575**	**1,638,499**	**1,510,828**	**1,046,488**	**987,422**	**917,984**	**420,730**	**382,332**	**399,249**	**299,356**	**268,746**	**193,594**
Alaska	2,746	2,607	2,536	2,253	2,154	2,055	28	28	27	465	424	455
Hawaii[3]	452	497	481	446	492	471	6	5	11	0	0	0
U.S. Total	**1,769,773**	**1,641,604**	**1,513,845**	**1,049,187**	**990,068**	**920,509**	**420,764**	**382,365**	**399,286**	**299,822**	**269,170**	**194,049**

[1] Equals purchased power plus exchange received plus wheeling received.
[2] Data for 1989 are preliminary.
[3] Hawaii includes nonutility transactions only.

Notes: •Totals may not equal sum of components because of independent rounding. •Summation of utility trade for utilities that operate within the NERC Region. •Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist. •Includes utility, import, export, and nonutility transactions.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 54. Utility Deliveries by North American Electric Reliability Council Region, Alaska, and Hawaii, 1987-1989

(Million Kilowatthours)

North American Electric Reliability Council Region, Alaska, and Hawaii	Total Deliveries[1]			Sales for Resale			Exchange Delivered			Wheeling Delivered		
	1989[2]	1988	1987	1989[2]	1988	1987	1989[2]	1988	1987	1989[2]	1988	1987
ECAR	245,874	232,759	203,923	152,703	159,063	134,897	72,177	58,661	58,745	20,994	15,036	10,281
ERCOT	76,668	75,182	72,681	32,355	31,905	30,085	35,017	35,364	36,053	9,297	7,913	6,543
MAAC	55,290	47,606	48,345	17,940	16,628	16,602	28,990	23,513	24,518	8,360	7,465	7,226
MAIN	60,612	56,863	50,534	23,746	21,291	23,395	35,661	33,666	25,123	1,205	1,906	2,017
MAPP(U.S.)	105,500	108,391	107,771	59,451	62,928	69,520	37,852	38,757	31,524	8,197	6,705	6,727
NPCC(U.S.)	164,638	154,736	135,192	99,653	97,267	99,725	22,634	19,380	15,456	42,351	38,089	20,011
SERC	375,248	330,155	335,334	277,693	261,562	265,950	75,670	56,850	59,468	21,885	11,743	9,966
SPP	134,684	125,734	117,047	96,202	94,034	88,488	18,558	11,743	18,741	19,924	19,956	9,818
WSCC(U.S.)	469,146	428,207	388,896	213,689	199,053	185,867	91,833	71,472	84,034	163,623	157,682	118,995
Contiguous U.S.	**1,687,660**	**1,559,633**	**1,459,774**	**973,432**	**943,731**	**914,528**	**418,392**	**349,406**	**353,661**	**295,836**	**266,496**	**191,584**
Alaska	2,705	2,590	2,543	2,244	2,177	2,096	*	0	1	461	413	446
Hawaii[3]	3	89	83	0	85	79	3	4	4	0	0	0
U.S. Total	**1,690,368**	**1,562,312**	**1,462,400**	**975,676**	**945,993**	**916,703**	**418,395**	**349,410**	**353,667**	**296,297**	**266,909**	**192,030**

[1] Equals sales for resale plus exchange delivered plus wheeling delivered.
[2] Data for 1989 are preliminary.
[3] Hawaii includes nonutility transactions only.
* Value less than 0.5.

Notes: •Totals may not equal sum of components because of independent rounding. •Summation of utility trade for utilities that operate within the NERC Region. •Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist. •Includes utility, import, export, and nonutility transactions.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 55. Utility Net Energy Flow by North American Electric Reliability Council Region, Alaska, and Hawaii, 1987-1989

(Million Kilowatthours)

North American Electric Reliability Council Region, Alaska, and Hawaii	Net Energy Flow[1]			Receipts[2]			Deliveries[3]		
	1989[4]	1988	1987	1989[4]	1988	1987	1989[4]	1988	1987
ECAR	-39,874	-46,647	-42,824	206,000	186,112	161,099	245,874	232,759	203,923
ERCOT	25,833	26,460	24,043	102,501	101,642	96,724	76,668	75,182	72,681
MAAC	30,977	28,780	22,528	86,267	76,386	70,874	55,290	47,606	48,345
MAIN	3,178	1,894	6,141	63,790	58,756	56,675	60,612	56,863	50,534
MAPP(U.S.)	8,746	6,363	-2,562	114,246	114,754	105,209	105,500	108,391	107,771
NPCC(U.S.)	19,361	23,927	24,344	183,999	178,664	159,536	164,638	154,736	135,192
SERC	8,416	18,369	4,141	383,664	348,524	339,525	375,248	330,155	335,384
SPP	5,552	4,582	-918	140,237	130,316	116,128	134,684	125,734	117,047
WSCC(U.S.)	16,726	15,138	16,161	485,872	443,345	405,057	469,146	428,207	388,896
Contiguous U.S.	**78,915**	**78,866**	**51,054**	**1,786,575**	**1,638,499**	**1,510,828**	**1,687,860**	**1,559,633**	**1,459,774**
Alaska	41	17	-7	2,746	2,607	2,536	2,705	2,590	2,543
Hawaii[5]	449	408	398	452	497	481	3	89	83
U.S. Total	**79,405**	**79,292**	**51,445**	**1,789,773**	**1,641,604**	**1,513,845**	**1,690,368**	**1,562,312**	**1,462,400**

[1] Equals receipts minus deliveries.
[2] Equals purchased power plus exchange received plus wheeling received.
[3] Equals sales for resale plus exchange delivered plus wheeling delivered.
[4] Data for 1989 are preliminary.
[5] Hawaii includes nonutility transactions only.

Notes: •Totals may not equal sum of components because of independent rounding. •Summation of utility trade for utilities that operate within the NERC Region. •Due to the complexity of electric power transactions that involve specifics of contracts, simultaneous energy transactions, the unintended receipt and delivery of energy (inadvertent flow), and losses, uniformity in reporting the classification and quantity of each transaction among utilities may not exist. •Includes utility, import, export, and nonutility transactions.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 56. Utility Purchases of Nonutility Generated Electricity by North American Electric Reliability Council Region, Alaska, and Hawaii, 1987-1989

(Million Kilowatthours)

North American Electric Reliability Council Region, Alaska, and Hawaii	1989[1]	1988	1987
ECAR	2,024	1,214	606
ERCOT	22,694	22,170	21,976
MAAC	5,479	2,550	871
MAIN	179	103	32
MAPP(U.S.)	148	97	73
NPCC(U.S.)	10,182	6,316	4,205
SERC	8,514	8,103	4,365
SPP	2,811	1,319	997
WSCC(U.S.)	37,145	25,939	16,787
Contiguous U.S.	**89,576**	**67,810**	**49,912**
Alaska	1	*	47
Hawaii	235	220	206
U.S. Total	**89,813**	**68,030**	**50,165**

[1] Data for 1989 are preliminary.
* Value less than 0.5 million kilowatthours.

Note: Totals may not equal sum of components because of independent rounding.

Source: Energy Information Administration, Form EIA-861, "Annual Electric Utility Report."

Table 57. Net Imports by North American Electric Reliability Council Region, Alaska, and Hawaii, 1987-1989

(Thousand Kilowatthours)

North American Electric Reliability Council Region, Alaska, and Hawaii	1989	1988	1987
ECAR	-5,426,212	164,437	770,056
ERCOT	-10,315	-11,762	-11,355
MAAC	NA	NA	NA
MAIN	NA	NA	NA
MAPP(U.S.)	-373,343	-1,279,546	3,325,019
NPCC(U.S.)	11,147,862	23,349,907	28,023,192
SERC	NA	NA	NA
SPP	NA	NA	NA
WSCC(U.S.)	5,637,853	9,546,828	14,230,947
Contiguous U.S.	**10,975,843**	**31,769,864**	**46,337,859**
Alaska	*	*	*
Hawaii	NA	NA	NA
U.S. Total	**10,975,843**	**31,769,864**	**46,337,859**

* Value less than 0.5.
NA = Not applicable.
Notes: •Totals may not equal sum of components because of independent rounding. •Values identify point of entry or exit, but do not necessarily identify point of consumption. •These data reflect electricity imported from Canada and Mexico. •Net imports data represent gross imports minus gross exports.
Source: Office of Fuels Programs, Fossil Energy, Form FE-781R, "Annual Report of International Electric Import/Export Data."

Operation and maintenance expenses consist of maintaining the physical condition and operating efficiency of the plant, including the generation room shown here.

Appendix A

Major Disturbances and Unusual Occurrences

Appendix A

Major Disturbances and Unusual Occurrences

Electric power systems are subject to a variety of incidents that, to a smaller or greater degree, may adversely affect the delivery of electricity to consumers. Among these are natural phenomena (such as storms and earthquakes); failure of electric system components; accidental or purposeful activities inimical to continued safe operation of electric power systems; and difficulties associated with the normal operation of large, extremely complex, real-time systems.

Under current Federal regulations, some disturbances are reported to the Federal Government. The legal basis for the requirements and the specifications of information reported are detailed in Title 10, Part 205, Subpart W, of the *Code of Federal Regulations*, Sections 205.350 through 205.353, published in the *Federal Register*, October 31, 1986. Underlying the formulation of the reporting criteria, requirements and procedures was the need for the Federal Government to be aware of potentially dangerous situations, tempered by the desire to minimize burden on the reporting utilities. Another consideration in the development of the rules was the benefit gained from knowledge of the causes and effects of undesired events that may have been caused by unforeseen system defects or by purposeful adverse actions to system design and operation. The final rules reflect modification of the preliminary rules, as published in the *Federal Register*, based on comments from the electric power industry and the general public.

In general, the incidents to be reported are grouped into two categories: mandatory in all cases; and mandatory if the incident meets specified criteria. A report is mandatory in all cases when, for the purpose of maintaining the reliability of the bulk power supply system, a utility (1) initiates a system voltage reduction of 3 percent or more, (2) disconnects circuits supplying over 100 megawatts of firm customer load, or (3) issues an appeal to the public for a voluntary reduction in the use of electricity. A report is also mandatory in regard to any actual or suspected act of sabotage or terrorism directed at the bulk power supply system. For the second category of mandatory incidents, the electric utility involved is permitted to exercise some judgment as to whether the criteria requiring mandatory reporting have been met.

In general, reports are to be made by telephone to the Emergency Operating Center, Department of Energy, in Washington, DC, as soon as practicable for instances of load shedding or loss of service, and, at the latest, within 3 hours of the beginning of a service interruption. For other disturbances, the allowable reporting time ranges from 24 hours to days. Written reports may be required by the Director, Office of Energy Emergency Operations, if the circumstances so indicate.

The operation of the bulk power system in the United States should be as trouble-free as possible. To that end, information is collected, as discussed above, regarding major disturbances to the normal functioning of that system. Events, such as damage to some local distribution circuits by storms or other uncontrollable events, do not greatly affect the supply of bulk power to the system as a whole. These events are more properly the concern of local and State authorities.

Data Sources

The information contained in Table A1 is based on data from the Form IE-417R, "Electric Power System Emergency Report." These data are collected by the Office of Energy Emergency Operations (under the Assistant Secretary for International Affairs and Energy Emergencies).

Table A1. Major Disturbances and Unusual Occurrences, 1989

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
3/13/89	2:45 AM	Quebec, Canada	Hydro-Quebec (NPCC)	[1]Solar Storm	21,000	NA	Noon Same Day
6/01/89	5:06 PM	Maryland, Washington, DC	Potomac Electric Power Company (PJM)	[2]Int.	305	47,500	7:23 PM Same Day
6/02/89	1:00 PM	Virginia	Virginia Power Company (SERC)	[3]5% VR	300	1,650,000	8:30 PM Same Day
6/05/89	12:30 AM	Washington, DC	Potomac Electric Power Company (PJM)	[4]Cable fire	35	500	8:00 AM Next Day
6/14/89	3:00 PM	Birmingham, Alabama	Alabama Power Company (SERC)	[5]Storms	200	51,000	10:00 PM Next Day
6/14/89	3:00 PM	Washington, DC	Potomac Electric Power Company (PJM)	[6]Storm	700	150,000	6/16/89
6/17/89	10:00 PM	Omaha, Nebraska	Omaha Public Power District (MAPP)	[7]Int	4	NA	4:00 AM Next Day
6/22/89	3:54 PM	Santa Clara, California	Santa Clara Electric Department (WSCC)	[8]Int	247	8,200	5:39 PM Same Day
6/25/89	5:27 PM	Hawaii	Hawaii Electric Light Company	[9]Int	NA	NA	6:03 PM Same Day
6/27/89	1:44 PM	Western Maryland	Potomac Edison Company (ECAR)	[10]VR	30	NA	6:00 PM Same Day
6/27/89	1:28 PM	PJM Service Area	PJM Interconnection (MAAC)	[11]VR	900	NA	6:00 PM Same Day
6/27/89	1:30 PM	Virginia Power Company Service Area	Virginia Power Company (SERC)	[12]VR	300	1,700,000	6:00 PM Same Day
7/01/89	3:38 PM	Kansas City, Kansas	Kansas City Power and Light Company (SPP)	[13]Lightning	200	About 510	6:15 PM CDT Same Day
7/10/89	4:15 PM	Connecticut, Massachusetts	New England Power Pool (NPCC)	[14]Storms	100	95,000	7/14/89
7/14/89	2:34 PM	South Carolina	South Carolina Electric and Gas Company (SERC)	[15]System Problem	NA	200,000	4:30 PM Same Day
7/14/89	2:04 PM	Pennsylvania, Maryland, Virginia	PJM Interconnection (MAAC)	[16]VR	168	1,270,000	7:25 PM Same Day
7/14/89	NA	Jim Bridger Power Plant, Wyoming	Pacific Power and Light Company (WSCC)	[17]Fire	None	None	Estimate One month
7/18/89	NA	Near Joliet, Illinois	Commonwealth Edison Company (MAIN)	[18]Lightning	None	None	NA
7/24/89	7:22 AM	Near Elkhorn City,	Appalachian Power Company	[19]Sabotage	None	None	8/7/89

See endnotes at the end of the table.

Table A1. Major Disturbances and Unusual Occurrences, 1989—Continued

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
		Kentucky	(ECAR)				
7/26/89	1:54 PM	PJM Area Service	PJM Interconnection (MAAC)	[R]High Load and VR	NA	NA	6:00 PM Same Day
7/26/89	2:45 PM	Long Island, New York	Long Island Lighting Company (NPCC)	[F]High Load	NA	NA	8:00 PM Same Day
8/04/89	9:58 AM	Glendale, California	Glendale Public Service Department (WSCC)	[P]Tie Line Trip	148	74,000	Noon Same Day
8/14/89	1:26 PM	Glendale, California	Glendale Public Service Department (WSCC)	[P]Disconnect Switch	63	NA	3:46 PM Same Day
8/14/89	2:51 PM	Lake Worth, Florida	City of Lake Worth Utilities (SERC)	[P]Lightning	57	26,000	3:40 PM EDT Same Day
8/16/89	1:30 PM	Canoga Park, California	NA	[P]Accident	NA	Test Facility	12:30 PM Next Day
8/20/89	4:11 PM	Central Florida	Florida Power Corporation and other systems (SERC)	[P]Int	2,970	132,000	5:17 PM Same Day
9/11/89	1:00 PM	Long Island, New York	Long Island Lighting Company (NPCC)	[F]High Load and VR	NA	NA	8:00 PM Same Day
9/18/89	Early AM	St. Croix, Virgin Islands	Virgin Islands Water and Power Authority	[P]Hurricane Hugo	NA	NA	Estimated-year-end
9/18/89	Early AM	St. Johns, Virgin Islands	Virgin Islands Water and Power Authority	[P]Hurricane Hugo	NA	NA	October-November
9/18/89	Early AM	St.Thomas, Virgin Islands	Virgin Islands Water and Power Authority	[P]Hurricane Hugo	NA	NA	70% by Oct 23
9/19/89	Mid-day	Puerto Rico	Puerto Rico Electric Power Authority	[P]Hurricane Hugo	NA	NA	Most by late September
9/22/89	AM	South Carolina, North Carolina	Duke Power Company (SERC)	[P]Hurricane Hugo	NA	686,348	10/9/89
9/22/89	8:00 AM	South Carolina	Carolina Power and Light Company (SERC)	[P]Hurricane Hugo	NA	140,000	10/9/89
9/22/89	10:00 AM	Virginia (S.W. Area)	Appalachian Power Company (ECAR)	[P]Hurricane Hugo	NA	92,127	9/24/89
9/22/89	10:00 AM	West Virginia (S.E. Area)	Appalachian Power Company (ECAR)	[P]Hurricane Hugo	NA	39,053	9/24/89
9/22/89	AM	South Carolina	South Carolina Electric and Gas Company (SERC)	[P]Hurricane Hugo	NA	300,000	NA
9/22/89	NA	Pennsylvania	West Penn Power Company (ECAR)	[P]Hurricane Hugo	NA	16,000	9/23/89

See endnotes at the end of the table.

Table A1. Major Disturbances and Unusual Occurrences, 1989—Continued

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
9/22/89	PM	Long Island, New York	Long Island Lighting Company (NPCC)	[25]Hurricane Hugo	NA	109,000	3:00 PM 9/23/89
9/22/89	AM	Central and Western Maryland	Potomac Edison Company (ECAR)	[25]Hurricane Hugo	NA	6,000	Evening Same Day
9/22/89	1:00 PM	West Virginia	Monongahela Power Company (ECAR)	[25]Hurricane Hugo	NA	17,000	Noon 9/24/90
9/22/89	AM	South Carolina	South Carolina Public Service Authority (SERC)	[25]Hurricane Hugo	NA	NA	NA
10/02/89	11:30 AM	Nassau County, New York	Long Island Lighting Company (NPCC)	[26]Cable Cut	NA	NA	2:00 PM Next Day
10/14/89	11:00 PM	Galveston Bay Area of Texas	Houston Lighting and Power Company (ERCOT)	[25]Hurricane Jerry	300	75,000	Morning 10/15/89
10/17/89	5:04 PM PST	Loma Prieta, California	Pacific Gas & Electric Company (WSCC)	[27]Earthquake	2,000	491,000	6:00 AM 10/23/89
10/17/89	5:04 PM	Santa Clara, California	Santa Clara Electric Department (WSCC)	[27]Earthquake	240	32,915	10/19/89 End of Day
10/17/89	5:04 PM	Alameda, California	Alameda Bureau of Electricity (WSCC)	[27]Earthquake	35	9,670	Within 2 hours
10/17/89	5:04 PM	Lodi, California	Lodi Municipal Electric System (WSCC)	[27]Earthquake	NA	53	6:00 PM Same Day
10/17/89	5:04 PM	Modesto, California	Modesto Irrigation District (WSCC)	[27]Earthquake	291	NA	NA
10/17/89	5:04 PM	Palo Alto, California	Palo Alto Electric Utility (WSCC)	[27]Earthquake	160	21,600	10/20/89
10/17/89	5:04 PM	Turlock, California	Turlock Irrigation District (WSCC)	[27]Earthquake	45	9,800	10/19/89
10/19/89	1:30 AM	Cincinnati, Ohio	Cincinnati Gas and Electric Company (ECAR)	[28]Winter Ice Storm	600	100,000	NA
11/08/89	3:59 PM MST	WSCC Area	Several systems in WSCC	[29]Trans Line Fault	260	NA	5:00 PM Same Day
11/16/89	6:00 AM	Huntsville and Northern Alabama	Tennessee Valley Authority (TVA) (SERC)	[25]Severe Weather	1,000	60,000	Several Days
11/20/89	11:30 PM	Washington, D.C. Area	Potomac Electric Power Company (MAAC)	[25]High Winds	NA	20,000	Noon Next Day
11/20/89	9:00 PM	Philadelphia, Pennsylvania Area	Philadelphia Electric Company (MAAC)	[25]High Winds	NA	90,000	Noon Next Day
11/20/89	4:00 PM	Long Island,	Long Island Lighting	[25]High Winds	NA	54,000	Noon

See endnotes at the end of the table.

Table A1. Major Disturbances and Unusual Occurrences, 1989—Continued

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
		New York	Company (NPCC)				Next Day
11/20/89	9:20 PM	Westchester, County, New York	Consolidated Edison of New York (NPCC)	[35]High Winds	NA	17,800	9:00 AM Next Day
12/04/89	7:00 AM	New England	New England Power Pool (NPCC)	[36]High Loads and 5% VR	NA	NA	8:00 PM Same Day
12/04/89	4:58 PM	Long Island, New York	Long Island Lighting Company (NPCC)	[37]VR	NA	NA	7:01 PM Same Day
12/04/89	4:58 PM	Consolidated Edison Area of New York	Consolidated Edison Company of New York (NPCC)	[38]Load Curtailed	NA	NA	6:02 PM Same Day
12/05/89	5:00 PM	New York State	New York Power Pool (NPCC)	[39]5% VR	NA	NA	5:52 PM Same Day
12/06/89	NA	Syracuse, New York	Niagara Mohawk Power Corporation (NPCC)	[40]Int and VR	NA	NA	7:00 PM Same Day
12/08/89	2:50 PM	Consolidated Edison Area of New York	Consolidated Edison Company of New York (NPCC)	[41]Load Curtailed	NA	NA	5:24 PM Same Day
12/13/89	5:00 PM	New York State	New York Power Pool (NPCC)	[42]5% VR	50	300,000	6:00 PM Same Day
12/14/89	6:00 PM	New England	New England Power Pool (NEPOOL)	[43]VR and PA	240	1,000,000	8:00 PM Same Day
12/16/89	AM	Homer, Alaska	Homer Electric Association	[44]Volcanic	NA	13,800	9:00 PM Same Day
12/22/89	7:35 AM	Washington, DC, Baltimore, MD	Potomac Electric Power Company Baltimore Gas and Elec (PJM)	[45]High Loads and VR	NA	NA	11:34 PM Same Day
12/22/89	9:23 AM	Houston, Texas	Houston Lighting and Power Company (ERCOT)	[46]2.5% VR	NA	NA	9:59 AM Same Day
12/22/89	10:00 AM	Houston, Texas	Houston Lighting and Power Company (ERCOT)	[46]5% VR	250	NA	11:00 PM 12/23/89
12/22/89	NA	Austin, Texas	Lower Colorado River Authority	[47]High Loads and PA	NA	NA	11:00 PM 12/23/89
12/22/89	10:30 AM	Abilene, Texas	West Texas Utilities Company	[48]PA	NA	NA	Noon Same Day
12/23/89	7:40 AM	Abilene, Texas	West Texas Utilities Company	[48]PA	NA	NA	12:40 PM Same Day
12/23/89	6:00 PM	St. Petersburg, Florida	Florida Power Corporation (SERC)	[49]VR	400	61,000	8:00 PM Same Day
12/23/89	7:15 AM	Corpus Christi,	Central Power	[50]PA	55.5	NA	10:37 AM

See endnotes at the end of the table.

Table A1. Major Disturbances and Unusual Occurrences, 1989—Continued

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
		Texas	and Light Company				Same Day
12/23/89	12:14 AM	Jacksonville, Florida	Jacksonville Electric Authority	[51]PA	211	50,000	12:44 PM Same Day
12/23/89	NA	Orlando, Florida	Orlando Utilities Commission	[52]High Loads	NA	4% of system	12/23/89 Same Day
12/24/89	8:50 AM	St. Petersburg, Florida	Florida Power Corporation (SERC)	[49]VR and PA	1,200	247,000	1:00 PM Same Day
12/24/89	6:56 AM	Jacksonville, Florida	Jacksonville Electric Authority	[51]5% VR	45	290,000	9:28 AM Same Day
12/24/89	10:03 AM	Jacksonville, Florida	Jacksonville Electric Authority	[51]5% VR	22	145,000	10:30 AM Same Day
12/24/89	6:00 AM	Lake Worth, Florida	Lake Worth Municipal Utility	[53]5 steps each 1.5% VR	12	NA	11:00 AM Same Day
12/24/89	NA	Tampa, Florida	Tampa Electric Company	[54]VR	NA	NA	12/25/89
12/24/89	6:08 AM	Miami, Florida	Florida Power and Light Company (SERC)	[55]VR	100 to 2,800	16% of system	11:30 AM Same Day
12/24/89	6:09 AM	Miami, Florida	Florida Power and Light Company (SERC)	[55]VR	100 to 2,800	16% of system	6:15 PM Same Day
12/24/89	8:18 AM	Miami, Florida	Florida Power and Light Company (SERC)	[55]VR	100 to 2,800	16% of system	10:17 AM Same Day
12/25/89	8:09 AM	St. Petersburgh, Florida	Florida Power Corporation (SERC)	[49]VR and PA	815	156,000	9:46 AM Same Day
12/25/89	6:00 AM	Lake Worth, Florida	Lake Worth Municipal Utility	[56]5 steps each 1.5% VR	11	NA	11:00 AM Same Day
12/25/89	4:57 AM	Miami, Florida	Florida Power and Light Company (SERC)	[55]VR	100 to 2,800	16% of system	11:14 AM Same Day
12/25/89	2:00 PM	Kissimmee, Florida	Kissimmee Utility Authority	[57]Circuit Breaker Tripped	190	31,000	3:30 PM Same Day
12/26/89	6:00 AM	Lake Worth, Florida	Lake Worth Municipal Utility	[58]2 steps each 1.5% VR	4	NA	11:00 AM Same Day
12/27/89	NA	Syracuse, New York	Niagara Mohawk Power Corporation	[59]PA	NA	NA	NA
12/29/89	NA	Consolidated Edison Area of New York	Consolidated Edison of New York (NPCC)	[60]Fire	180	137,070	5:05 PM Same Day
12/30/89	NA	Consolidated Edison Area of New York	Consolidated Edison of New York (NPCC)	[61]Fire	NA	NA	NA

See endnotes at the end of the table.

Table A1. Major Disturbances and Unusual Occurrences, 1989—Continued

Date	Time	Area	Utility/Power Pool (NERC Council)	Type of Disturbance	Loss (megawatt)	Number of Customers Affected	Restoration Time
12/31/89	NA	Bangor, Maine	Bangor Hydroelectric Company	[43]Switch Tripped	NA	90,000	Same Day

[1] A severe solar system storm caused shutdown of the Hydro-Quebec system, cutting off sales of power by Hydro-Quebec to New England and New York. There were no disruptions of service in New York or in New England and both of those areas were able to supply power to assist Hydro-Quebec. Voltage fluctuations, unusual noise in transformers, and some tripping of capacitor banks occurred in the WSCC area, apparently caused by solar magnetic effects but not related to the situation in Quebec.

[2] Failure of a secondary bushing on a 69-kilovolt circuit breaker resulted in the destruction of that breaker, a fire, and damage to other facilities in the Bells Mill substation. Five other substations were shut down by protective relay equipment as a result of the damage to Bells Mill substation.

[3] Voltage reduction necessitated by unseasonal high temperatures causing unusually high loads, 3 nuclear units out of service for maintenance and refueling, 2 large fossil units out for maintenance, 2 smaller units out for maintenance, inability to import desired purchase capacity because of low voltage on seller's (APS) transmission system, forced outage of Possum Point No. 5 (a large fossil unit belonging to PEPCO).

[4] Fire in a manhole on M Street N.W. damaged 13.2-kilovolt underground cables and spread to other manholes. Commercial and government office buildings in central D.C. lost all power and some 15,000 employees were affected. Federal agencies without electricity were: Federal Communications Commission; the Washington Office of the U.S. Secret Service; Administrative Council of the United States; Railroad Retirement Board. Traffic signals in the area were inoperable and several streets were closed by police.

[5] A severe thunderstorm and high winds damaged distribution and subtransmission circuits.

[6] The most severe storm in PEPCO history downed about 500 distribution lines, knocked down poles and trees and required massive reconstruction.

[7] During work in an underground transformer vault a short circuit occurred on the 480-volt secondary of a 13.8-kilovolt/480-volt transformation. Three men were injured (one died the next day from burns) and service to downtown Omaha was interrupted.

[8] Damage to a transformer at Kefer Receiving Station; cause not known.

[9] An earthquake near the Island of Hawaii caused several distribution circuits to trip. There was no damage to generating plants or transmission facilities.

[10] Loss of a Chalk Point unit on the Potomac Electric Power Company system caused power flow and voltage level problems that forced Potomac Edison Company to reduce its entire system voltage by 5 percent in order maintain system integrity.

[11] As a result of the loss of a Chalk Point unit on the system of Potomac Electric Power Co. (PEPCO) the entire PJM system had to reduce voltage by 5 percent. The Potomac Edison Company also had to reduce voltage by 5 percent.

[12] A 5-percent voltage reduction was needed as a result of PEPCO's loss of unit at Chalk Point.

[13] Lightning struck one of the 161-kilovolt transmission lines on the low side of the 345-kilovolt/161-kilovolt transformation at Hawthorn Substation. The line circuit breaker failed to trip and the backup relaying also failed to operate. Other circuit breakers in the substation tripped, opening the 345-kilovolt and 161 kilovolt busses. Some equipment sustained minor damage.

[14] Thunderstorms caused numerous distribution circuit outages.

[15] System operating problems caused voltage fluctuations and loss of several generating units including V.C. Summer Nuclear Unit.

[16] Lack of sufficient operable generating capacity to meet increasing load necessitated a 5-percent voltage reduction by Potomac Electric Power Company and the Baltimore Gas and Electric Company members of the PJM Power Pool. In order to prevent break-up of the interconnected system the Allegheny Power System (ECAR) and Virginia Power Company (SERC) also reduced voltage by 5 percent.

[17] Electrical failure on the low-voltage side of the 560 MVA generator transformer for one of the four 500-megawatt generating units at the plant (near Rock Springs, Wyoming) caused a fire that damaged the transformer and overhead conductors leading to the switchyard. There was no loss of service.

[18] During an electrical storm the reactor containment buildings of Braidwood Nuclear Units 1 and 2 were struck by lightning. The two strikes, about 6 minutes apart, caused overvoltage relays on the reactor control rods to operate and shut down the units. There was no damage to the plant.

[19] One tower of a 765-kilovolt transmission line fell because it was damaged by explosives.

[20] Heavy loads and inability to obtain purchased power from systems to the west (ECAR area) made a 5-percent voltage reduction necessary.

[21] Heavy loads required Long Island Lighting Company (LILCO) to institute Stage 2 of their Power System Emergency Alert Procedure: reduce LILCO in-house use of power; request some 500 large industrial customers and 16 transmission-line customers to reduce or interrupt their loads; implement direct load control of residential air conditioners, water heaters and swimming pool pumps; issue a radio appeal to the public to reduce the use of power.

[22] City of Glendale has it own generators supplemented by power from the Los Angeles Department of Water and Power. One line was out of service and the second line failed. The load exceeded the capacity of Glendale's own generators and the system failed.

[23] Failure of a disconnect switch on a distribution circuit in the central business district caused loss of power on the circuit.

[24] Lightning. No details available.

[25] Power Supply to 9 offices and 3 test facilities of the Department of Energy's ETEC Test Facility at the Santa Susanna Field Laboratory in San Francisco was interrupted when a contractor, installing a groundwater monitoring well, inadvertently drilled through a 4,160-volt cable. Power to the offices was restored at 3:30 PM on the same day. Power to the Test Facility was restored on August 17.

[26] The 500-kilovolt interconnections between Florida Power Corporation and the Southern Company (Georgia) tripped. Frequency declined to 59.37 hertz, causing automatic shedding of load by under-frequency relays. Sixteen utilities shed a total of 2,970 megawatts including 1,576 megawatts in the service area of Florida Power and Light Company; 500 megawatts on the Florida Power Corporation system, 275 megawatts on Jacksonville Electric Authority's system and 260 megawatts on the system of Tampa Electric Company. The incident was caused by failure of a 500-kilovolt switch at Georgia Power Company's Plant Hatch and a resultant phase-to-phase short circuit on the Duval (Florida) to Hatch (Georgia) 500-kilovolt transmission line. At the time of the fault the Southern Company (including Georgia Power) was supplying 3,136 megawatts to the Florida systems.

[27] High loads, loss of Nine Mile Point 2 (LILCO share 179 megawatts) and some forced and scheduled generator outages required LILCO to institute load control measures at 1:00 PM. Later loss of 3 gas turbines forced implementation of a 5-percent voltage reduction at 4:48 PM. Voltage was restored to normal at 6:15 PM and the load control measures were cancelled at 8:00 PM.

[28] Hurricane Hugo struck the Virgin Islands during the early morning of September 18, moved on to Puerto Rico on the 19th and hit the coast of South Carolina on the 22nd. It then moved inland in a northwesterly direction, turned north and then veered eastward. Most of the hurricane's force was spent by the time it left the Carolinas. Because a large number of systems were involved it is impracticable to list in detail all the damage that was done. Many transmission line towers and structures were knocked down by the force of the winds. As towers and poles fell they broke conductors, unbalancing the stress of unbroken lines on other structures and making them more susceptible to the winds. The same is true of distribution lines, which suffered additionally from the effects of broken trees and flying debris. No generating plants were reported as damaged.

[29] An underground cable to Nassau Community College was inadvertently cut by a bulldozer during construction work on an office building project. Several U.S. Navy buildings near the College, and some residences, also lost power.

[30] Hurricane Jerry caused an interruption of power supply.

[31] An earthquake struck the San Francisco area (epicenter near Loma Prieta), damaging Pacific Gas and Electric Company electric and gas facili-

ties and interrupting power to approximately 565,000 customers on a number of systems. On the Pacific Gas and Electric system the bulk power supply facility that suffered the most damage was the Moss Landing Plant, where the switchyard was partially destroyed; at Metcalf substation all the 500-kilovolt circuit breakers were destroyed. At several PG&E plants generating units tripped as the electrical shock was transmitted through the system and transmission lines opened. Distribution circuits were destroyed in some areas, particularly the Marina area of San Francisco and in Santa Cruz. Systems other than PG&E do not appear to have suffered damage to electrical facilities to any extent; loss of customer service seems to have resulted from electrical disturbances to the interconnected system caused by loss of PG&E lines and load. The sudden loss of a large part of the PG&E load caused high voltage in some parts of the interconnected system and some frequency fluctuations. Tripping of transmission lines and loss of some generators on the PG&E system, combined with the physical shock of the earthquake, caused protective relays to operate and trip some loads on surrounding systems.

[32] Ice storm caused distribution circuits to fail.

[33] A short circuit of one phase to ground occurred on the Broadview-Garrison No. 1 500-kilovolt line and was closely followed by a similar fault on the No. 2 line. As a result of the consequent abnormal flows of current on the interconnected system several lines and generating units tripped in Montana, Colorado, New Mexico, Utah and Wyoming. Low frequency was experienced by Southern California Edison Company and the PacificCorp Electric System East; South Dakota and Idaho were also affected.

[34] A severe weather front including tornadoes destroyed a 46-kilovolt/12-kilovolt substation and a number of transmission line structures at the 161-kilovolt level. A public appeal for conservation of electricity was issued.

[35] A severe windstorm over the mid-Atlantic states caused numerous interruptions of customer service on several systems. Five 69-kilovolts transmission lines on the LILCO system were temporarily put out of service by the winds, as were lines on the PEPCO system at voltage levels of 69 kilovolts, 34 kilovolts and 13 kilovolts. No damage to generating plants was reported by any system. In addition to the customer outages listed in the table, other outages (but no details) were reported as follows: Baltimore Gas and Electric Company 70,000; Pennsylvania Power and Light Company 113,000; Altantic City Electric Company 5,000; Delmarva Power and Light Company 8,000.

[36] The system experienced a deficiency of generating capacity due to unexpected high loads, cutback of purchased power deliveries from New York and a number of unplanned outages of NEPOOL generating units. Public appeals for power conservation were issued, a 5-percent voltage reduction was put into effect and various other load reduction measures were employed. The actual peak load served was 19,082 megwatts. It is estimate that the load would have been 19,800 megawatts if all the load reduction measures had not been used. There was no actual disconnection of customers. The difficulties began about 7:00 AM and were essentially over by about 8:00 PM.

[37] Large bulk power customers served directly from transmission lines were requested to curtail their loads due to shortage of reserve generating capacity on the New York Power Pool System. The request was issued 4:58 PM and was rescinded at 7:01 PM.

[38] Curtailment of some loads was instituted at 4:58 PM in cooperation with Long Island Lighting Company and other member systems of the New York Power Pool. The restriction was lifted a 6:02 PM.

[39] A pool-wide voltage reduction of 5 percent was ordered at 5:00 PM and was cancelled at 5:52 PM.

[40] The company was requested by the New York Power Pool to institute load reduction measures because the Pool was short of reserve generating capacity. The company took the following measures: interrupted customers served under contracts for interruptible service; curtailed the company's own use of power; asked large customers to voluntarily cut their use of power. No estimate of number of customers affected or magnitude of power reduction achieved is available. The emergency was terminated at about 7:00 PM.

[41] At the request of the New York Pool, New York which expected a shortage of reserve capacity during the afternoon, the company requested its major consumers to curtail their loads at 2:50 PM. The system was restored to normal at 5:24 PM.

[42] Pool members having facilities for manual voltage reduction were requested to implement a 5-percent reduction such that adequate operating reserve would be available for the peak load period from 5:00 PM to 6:00 PM. About 300,000 customers were affected and load was reduced by about 50 megawatts.

[43] Manual and automatic voltage reductions and a public appeal were initiated at 6:00 PM, affecting about 1 million customers and resulting in a load reduction of about 240 megawatts. The actions were cancelled at 8:00 PM. Cold weather caused high loads and unexpected forced outages caused reserve margins to decline below the minimum set by standards for reliable service.

[44] About 3,800 customers were affected by outages lasting up to 8 hours and some 10,000 customers suffered momentary outages all due to volcanic ash from an eruption of Mt. Redoubt settling on 14,400-volt lighting arrestors, cutouts and other apparatus, causing flashovers. The disturbance began in the morning on December 16 and continued until about 9:00 PM.

[45] Both companies instituted a 5-percent voltage reduction between 7:35 AM and 11:34 AM because cold weather caused unexpected high loads and problems in delivery of No. 6 fuel oil required for system operation, such that oil would be conserved.

[46] Unusually widespread severe cold weather caused unexpected load increases and difficulty in operation at some power plants with outdoor facilities not designed for operation under such weather conditions. In addition the cold weather increased residential use of natural gas and reduced the gas available to power plants. A 2.5-percent voltage reduction was instituted at 9:23 AM and was superseded by a 5-percent reduction at 10:00 AM. The 5-percent reduction in voltage is estimated to to have reduced load by about 250 megawatts.

[47] Unusually cold weather caused unexpected load increases. A public appeal was issued for conservation of electricity.

[48] Extreme cold weather caused unusually high demand and a variety of mishaps reduced the generating capacity that was available. A public appeal for load conservation was made on December 22 at 10:30 AM and was cancelled at 12:00 noon. There was no interruption of service to customers. On December 23 a public appeal to reduce load was made at 7:40 AM and was rescinded at 12:40 PM.

[49] Due to unexpected cold weather, loads were very high. A public appeal to conserve electricity was issued, voltage reduction and load management programs were implemented, interruptible customers were interrupted, curtailable customers were curtailed and some firm load was interrupted via rotating blackouts. The rotating blackouts involved 61,000 customers and 400 megawatts of load on December 23 (6:00 PM to 8:00 PM; 247,000 customers and 1,200 megawatts of load on December 24 8:50 AM to 1:00 PM); 156,000 customers and 815 megawatts of load on December 25 (8:09 AM to 9:46 AM).

[50] A radio appeal was made for reduction of load at 7:15 AM and the appeal was carried on TV at 9:00 PM. The company shed 35 megawatts of firm load about 10:20 AM and by 10:27 AM this had increased to about 55.5 megawatts. By 10:37 AM the load that had been shed was restored. The company's use of natural gas was restricted and some loss of generating capacity was experienced. The situation was due to abnormally cold weather over most of the state of Texas. The public appeal was cancelled on the morning of December 24.

[51] Extreme cold weather caused difficulties in the operation of the Authority's system due to high demand, tie-line overloads and the forced outage of two 600 megawatt generating units. A public appeal to reduce loads was issued on December 23 at 12:14 PM and was rescinded at 12:44 PM on the same day; about 50,000 customers and some 211 megawatts of load were affected. On December 24 a 5-percent voltage reduction was instituted at 6:56 AM and was cancelled at 9:28 AM, affecting about 290,000 customers and reducing load by about 45 megawatts. A 5-percent voltage reduction was again in effect to December 24 from 10:03 AM to 10:30 AM, affecting 145,000 customers and reducing load by about 22 megawatts.

[52] Extremely cold weather caused high loads. High demands and loss of some generation necessitated a voltage reduction of 2.5 percent and 4 percent of the system's customers were shed from some 10 minutes.

[53] Cold weather caused unusual demand on the system. Automatic voltage reduction, in 5 steps of 1.5 percent each, was implemented, a 30-year old generating plant in cold stand-by was re-activated and the Municipal Water and Sewer Department was asked to operate its emergency generator. About 12 megawatts load was lost due to the voltage reduction.

[54] Load reductions and curtailments due to unusually cold weather and increased electrical demand for heating.

[55] Extremely low temperatures beginning on the morning of December 24, caused Florida Power and Light to experience energy deficiencies due to a combination of high loads, generating unit maintenance outages, gas supply shortages and forced outages of generating units. Rotating feeder interruptions were instituted. During the 2-day problem period there were pubic appeals to reduce use of electric power. The maximum number of customers without service at one time was about 480,000 (some 16% of the load). Altogether, about 40 percent of the system's customers experienced outages during the rotating blackouts.

[56] Same situation occurred as on December 24. This time load reduction was about 11 megawatts.

[57] A 59-kilovolt breaker tripped, system ties to other utilities were overloaded, and the Kissimmee system then separated from the Florida Interconnected System.

[58] Same situation as December 24 and 25. This time only 2 voltage reduction steps (1.5 percent each) were implemented. The loss reduction was

estimated to have been 4 megawatts.

[59] New York Pool declared the region to be in "Reserve Condition No. 1". Utilities were to have appeal to customers for curtailed use of electricity.

[60] Fire in the Hell Gate switching station caused cutoff of electric power to the Yorkville and Bronx service areas of the company. The fire was believed to have been caused by rupture of a natural gas line that passed through or near the switching station, which was formerly a generating plant.

[61] Power supply to an area in the Bronx was out for an hour due to a gas line fire.

[62] Complete outage due to a switch station falling on a 70-MVA transformer. Some 90,000 customers lost service for an hour.

Note: The rules promulgated in the Code of Federal Regulations (10 CFR Part 205) and published in the **Federal Register** of October 31, 1986, do not require utilities to report distribution system outages that are local in nature and affect only a small area or a small number of customers. Utilities may report such outages if they so desire.

EDT = Eastern Daylight Time.
EST = Eastern Standard Time.
Int = Interruption.
LF = Line Fault (Accidental contact of energized conductors or of energized conductors with ground).
LR = Load Reduction.
LTNG = Lightning Strike.
MAST = Mountain Advanced Standard Time.
MW = Megawatts.
NA = Not Available.
PA = Public Appeal.
PJM = Pennsylvania, New Jersey, Maryland.
UO = Unusual Occurrence.
VR = Voltage Reduction.
Source: International Affairs and Energy Emergencies, Form IE-417R, "Electric Power System Emergency Report."

Appendix B

References

Appendix B

References

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Appendix C

Technical Notes

Appendix C

Technical Notes

Sources of Data

The *Electric Power Annual* is prepared by the Electric Power Division; Office of Coal, Nuclear, Electric and Alternate Fuels; Energy Information Administration (EIA); U.S. Department of Energy (DOE). Data published in the *Electric Power Annual* are compiled from two statistical forms filed monthly and seven forms filed annually by electric utilities. Those forms are: the Form EIA-759, "Monthly Power Plant Report"; the FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"; the Form EIA-861, "Annual Electric Utility Report"; the Form EIA-860, "Annual Electric Generator Report"; the Federal Energy Regulatory Commission (FERC) Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others"; the Form EIA-412, "Annual Report of Public Electric Utilities"; the Form EIA-767, "Steam-Electric Plant Operation and Design Report"; the Department of Energy Form IE-411, "Coordinated Bulk Power Supply Program"; and the Department of Energy, Form FE-781R, "Annual Report of International Electric Import/Export Data." In addition, the *Electric Power Annual* also includes data collected on the Form IE-417R, "Electric Power System Emergency Report." A brief summary of each form is presented below.

Form EIA-759

The Form EIA-759 is a mandatory census of all operators of electric utility plants producing electric power for public use. The Form EIA-759 is used to collect monthly data on net generation consumption of coal, petroleum, and natural gas; and end-of-the-month stocks of coal and petroleum for each plant by prime mover and fuel-type combination. Summary data from the Form EIA-759 are also published in the *Electric Power Monthly (EPM)*, the *Monthly Energy Review (MER)*, *Annual Outlook for U.S. Electric Power(AOEP)*, and the *Annual Energy Review (AER)*. These reports present aggregated data for electric utilities at the U.S., Census division, and North American Electric Reliability Council Region (NERC) levels.

Instrument and Design History. Prior to 1936, the Bureau of the Census and the U.S. Geological Survey collected, compiled, and published data on the electric power industry. In 1936, the Federal Power Commission (FPC) assumed all data collection and publication responsibilities for the electric power industry and implemented the FPC Form 4. The Federal Power Act, Sections 311 and 312, and FPC Order 141 define the legislative authority to collect power production data. The Form EIA-759 replaced the FPC Form 4 in January 1982.

Data Processing. The Form EIA-759, along with a return envelope, is mailed to respondents approximately 4 working days before the end of the month. The respondents names are obtained from a computerized mailing address file. The completed forms are to be returned to the EIA by the 10th day after the end of the reporting month. After receipt, data from the completed forms are manually logged in and edited before being keypunched for automatic data processing. An edit program checks the data for errors not found during manual editing. The electric utility companies are telephoned to obtain data in cases of missing reports and to verify data when questions arise during editing. Following verification of the data, text and tables of aggregated data are produced for inclusion in the *EPM*. Following EIA approval of the *EPM*, the data are made available for public use, on a cost-recovery basis, through custom computer runs, data tapes, or in publications.

FERC Form 423

The FERC Form 423, a restricted-universe census, is a monthly record of delivered-fuel purchases, submitted by approximately 225 electric utilities for each plant with a fossil-fueled steam-electric nameplate capacity of 50 or more megawatts. Summary data from the FERC Form 423 are also published in the *EPM*, the *MER*, and the *Cost and Quality of Fuels for Electric Utility Plants - Annual*. These reports present aggregated data on electric utilities at the U.S. and Census division level.

Instrument and Design History. On July 7, 1972, the FPC issued Order Number 453 enacting the New Code of Federal Regulations, Section 141.61, legally creating

the Form 423. Originally, the form was used to collect data only on fossil-steam plants, but was amended in 1974 to include data on internal combustion and combustion turbines. The FERC Form 423 replaced the FPC Form 423 in January 1983. Peaking units, which were previously collected on the FPC Form 423 were eliminated from the FERC Form 423. In addition, the nameplate capacity threshold was changed from 25 megawatts to 50 megawatts. This reduction in coverage eliminated approximately 50 utilities and 250 plants. All FPC Form 423 historical data in this publication have been revised to reflect the new nameplate capacity threshold of 50 or more megawatts.

Data Processing. A computerized mailing-address file is used to send a 6-month supply of forms to respondents semiannually. Completed forms are to be returned to the EIA by the 45th day following the end of the reporting month. Data from the completed forms are manually logged in and edited before being keypunched for automatic data processing. The electric utility companies are telephoned to obtain data in cases of missing reports and to verify data when questions arise during editing. Following verification of the data, text and tables of aggregated data are produced for inclusion in the *EPM*. After the *EPM* receives EIA approval, the data become available for public use, on a cost-recovery basis, through custom computer runs, data tapes, or in publications.

Form EIA-861

The Form EIA-861 is a mandatory census of electric utilities in the United States, its territories, and Puerto Rico. The Form EIA-861 data contained in this publication are for the United States only. The survey is used to collect information on power production and sales of electricity from approximately 3,250 electric utilities. The data collected are used to update the electric utility frame data base maintained by the EIA. This data base supports queries from the Executive Branch, Congress, other public agencies, and the general public. Summary data from the Form EIA-861 are also contained in the *EPM;* the *Electric Sales, Revenue, and Bills;* the *Financial Statistics of Selected Electric Utilities;* and the *Annual Outlook for U.S. Electric Power.* These reports present aggregate totals for electric utilities on a national level, by State, and by ownership type.

Instrument and Design History. The Form EIA-861 was implemented in January 1985 to collect data as of year-end 1984. The Federal Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Data Processing. The Form EIA-861 is mailed to the respondents in February to collect data as of the end of the preceding calendar year. The completed forms are to be returned to the EIA by May 1. The data are manually edited before being entered into the interactive on-line system. Internal edit checks are performed to verify that current data total across and between schedules, and are comparable to data reported the previous year. Edit checks are also performed to compare data reported on the Form EIA-861 and similar data reported on the Forms EIA-826, "Monthly Electric Utility Sales and Revenue Report with State Distributions," the FERC Form 1, and the Form EIA-412, "Annual Report of Public Electric Utilities." These are utility-level checks. Respondents are telephoned to obtain clarification of reported data and to obtain missing data.

Form EIA-861 figures shown in this publication differ somewhat from the sum of the monthly Form EIA-826 figures for sales published in the *EPM* and in issues of the *Electric Power Annual* prior to 1988. Both forms use sectoral classifications (residential, commercial, and industrial) based on the usual classification of consumers by electric utilities. At the national level, the Form EIA-861 and Form EIA-826 figures corresponded closely (within 3 percent) for all end-use sectors. Some larger differences were observed at the State level particularly for Tennessee due to a misclassification of commercial and industrial data in the Form EIA-826 survey.

Detailed comparisons and descriptions of conceptual problems affecting the quality of the data are discussed in the report, *An Assessment of the Quality of Selected EIA Data Series: Electric Power Data.* (See Appendix B for the reference.) One example of such a problem inherent in data on electricity sales is that the sectoral classification scheme can vary from utility to utility as influenced by the local public utility commission.

Differences between the Form EIA-861 and Form EIA-826 figures can result from the Form EIA-826 sampling procedure and/or from nonsampling error in either data collection. One source of nonsampling error in the Form EIA-826 stems from the practice of filing estimates when the actual figures are not yet available. Although respondents are instructed to file revisions, revisions are not always filed. In addition, the respondents have been instructed to review their Form EIA-826 figures at the end of the reporting year to ensure consistency with Form EIA-861 figures. The EIA compares these data series and attempts to resolve any differences. Nevertheless some reporting differences remain.

Form EIA-860

The Form EIA-860 is a mandatory census of electric utilities in the United States that operate power plants or plan to operate a power plant within 10 years of the reporting year. The survey is used to collect data on existing power plants from the electric utilities and their 10-year plans for constructing new plants, and modifying and retiring existing plants. Data on the survey are collected at the generating unit level. These

data are then aggregated to provide totals by energy source (coal, petroleum, gas, water, uranium, other) and geographic area (State, NERC region, Federal region, Census division). Additionally, at the national level, data are aggregated to provide totals by prime mover. Data from the Form EIA-860 are also summarized in the *Inventory of Power Plants in the United States*, and are used as input to publications and studies by other offices in the DOE.

Instrument and Design History. The Form EIA-860 was implemented in January 1985 to collect data as of year-end 1984. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data.

Data Processing. The Form EIA-860 is mailed to approximately 900 respondents in December and the completed forms are to be returned to the EIA by February 15 containing data as of the end of the preceding calendar year. Data for each respondent are preprinted from the applicable data base. Respondents are instructed to verify all preprinted data and to supply missing data. The data are manually edited before being keyed for automatic data processing. Computer programs containing additional edit checks are run. Respondents are telephoned to obtain correction or clarification of reported data and to obtain missing data, as a result of the manual and automatic editing process.

FERC Form 1

The FERC Form 1 is a mandatory restricted-universe census of major investor-owned electric utilities having, in each of the last 3 consecutive years, sales or transmission service that exceeds any one or more of the following: (1) 1 million megawatthours of total sales, (2) 100 megawatthours of sales for resale, (3) 500 megawatthours of gross interchange out, or (4) 500 megawatthours of wheeling for others (deliveries plus losses). All major investor-owned electric utilities, licensees, or others subject to the Federal Power Act of 1935 must submit this form annually to the FERC through the EIA. Classification of such entities is provided in the FERC Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. Approximately 180 electric utilities are classified as major. Excluded from EIA publications are Northeast Nuclear Energy Company, whose data were not included to prevent double counting of data for the Millstone nuclear plant, which Northeast Nuclear Energy Company operates for Connecticut Light & Power Company and Western Massachusetts Electric Company; and Golden Spread Electric Cooperative, whose data were not included since it is classified as a cooperative electric utility on the Form EIA-861. The FERC, however, has determined that Golden Spread Electric Cooperative should file a FERC Form 1 under Section 201 of the Federal Power Act.

The FERC Form 1 is used to collect data on income and earnings, taxes, depreciation and amortization, distribution of salaries and wages, electric operating revenues, electric maintenance expenses, generating plant statistics, planned construction data, year-end balance sheets, and general corporate information. Respondents are required to report data on historical plant cost and power production expenses for their hydroelectric plants with a generator nameplate capacity of 10 or more megawatts each steam-electric plant with a generator nameplate capacity of 25 or more megawatts; and each gas-turbine plant with a generator nameplate capacity of 10 or more megawatts. Less detailed data are required for other plants.

Instrument and Design History. The Federal Power Commission's (FPC) Form 1, the predecessor of the FERC Form 1, was implemented in 1935 by the FPC. When the FPC was merged with the DOE in October 1977, the collection and processing of data on the form became the responsibility of the EIA. This mandatory survey is conducted in accordance with the FERC Uniform System of Accounts for Private Utilities and Licensees.

Data Processing. The completed forms are to be returned to the EIA on or before April 30, containing data for the preceding calendar year. Manual editing of the reported data is completed prior to data entry. Additional edit checks of the data are performed through computer programs. The program edits include both deterministic checks, in which records are checked for the presence of data in required fields, and statistical checks, in which the data are checked against a range of values based on historical data values and for logical or mathematical consistency with data elements reported in the form. Discrepancies found in the data, as a result of these checks, are resolved either by the processing office or by further information obtained from a telephone call to the respondent company.

Form EIA-412

The Form EIA-412 is a restricted-universe census used annually to collect accounting, financial, and operating data from publicly owned electric utilities in the United States. Those publicly owned electric utilities engaged in the generation, transmission, or distribution of electricity which had 120,000 megawatthours of sales to ultimate consumers and/or 120,000 megawatthours of sales for resale for the 2 previous years, as reported on the Form EIA-861, "Annual Electric Utility Report," must submit the Form EIA-412. The criteria used to select the respondents for this form results in approximately 450 publicly owned utilities.

Federal electric utilities are required to file the Form EIA-412. The financial data for the U.S. Army Corps of Engineers (except for Saint Mary's Falls at Sault St. Marie, Michigan); the U.S. International Boundary and

Water Commission; and the U.S. Department of Interior, Bureau of Reclamation were collected on the Form EIA-412 from the Federal power marketing administrations.

Data on plant construction cost, production expenses, generating equipment characteristics, and other relevant operating data are also published in *Electric Plant Cost and Power Production Expenses.*

Instrument and Design History. The FPC created the Form 1M in 1961 as a mandatory survey. It became the responsibility of the EIA in October 1977 when the FPC was merged with DOE. In January 1980, the Form 1M was superseded by the Form EIA-412, also a mandatory survey. Data currently reported on the Form EIA-412 are the same as that previously reported on the FPC Form 1M.

Data Processing. The processing of data reported on this form is the responsibility of the Data Systems Branch, Electric Power Division of the Office of Coal, Nuclear, Electric and Alternate Fuels. The completed forms are due in this office on or before April 30. Nonresponse follow-up procedures are used to attain 100-percent response. Automated systems are used to edit data from the surveys using deterministic and statistical checks. When all data have passed the edit process, the data are aggregated into a master file that is used as input to the publication.

Form EIA-767

The Form EIA-767 is a mandatory restricted-universe census of all electric power plants with a total existing or planned organic- or nuclear-fueled steam-electric generator nameplate rating of 10 or more megawatts. The entire form is filed by approximately 700 power plants with a nameplate capacity of 100 or more megawatts. An additional 200 power plants with a nameplate capacity between 10 and 100 megawatts submit information only on fuel consumption/quality, boiler/generator configuration, and flue-gas desulfurization equipment, if applicable. The Form EIA-767 is used to collect data annually on plant operations and equipment design (including boiler, generator, cooling system, flue gas desulfurization, flue gas particulate collectors, and stack data). Data from the Form EIA-767 are used for economic, regulatory, and environmental analyses conducted by the DOE, the FERC, the Environmental Protection Agency, and the Department of Commerce.

Instrument and Design History. The Federal Energy Administration Act of 1974 (Public Law 93-275) defines the legislative authority to collect these data. The predecessor form, FPC-67, "Steam-Electric Plant Air and Water Quality Control Data," was used to collect data from 1969 to 1980, when the form number was changed to Form EIA-767. In 1982, the form was completely redesigned and given the name Form EIA-767, "Steam-Electric Plant Operation and Design Report." In 1986, the respondent universe of 700 was increased to 900 to include plants with nameplate capacity from 10 megawatts to 100 megawatts. Respondents for these 200 additional plants complete only pages 1, 5, 6, and, if applicable, 13, and 14.

Data Processing. The Form EIA-767 is mailed to respondents in January to collect data as of the end of the preceding calendar year. The completed forms are to be returned to the EIA by May 1. Equipment design data for each respondent are preprinted from the applicable data base. Respondents are instructed to verify all preprinted data and to supply missing data. The data are manually reviewed before being keyed for automatic data processing. Computer programs containing additional edit checks are run. Respondents are telephoned to obtain correction or clarification of reported data and to obtain missing data, as a result of the manual and automatic editing process.

Form IE-411

The Form IE-411 is filed annually as a voluntary report. The information reported includes: (1) actual energy and peak demand for the preceding year and 10 additional years; (2) existing and future generating capacity; (3) scheduled capacity transfers; (4) projections of capacity, demand, purchases, sales, and scheduled maintenance; (5) assessment of adequacy; (6) generating capacity unavailability; (7) bulk power system maps; (8) near term transmission adequacy; (9) future critical bulk power facilities that may not be in service when required; and, (10) system evaluation criteria. These data support queries from the executive branch, Congress, other public agencies, and the general public. These reports present various council aggregate totals for their member electric utilities, with some nonmember information included.

Instrument and Design History. The Form IE-411 program was initiated under the Federal Power Commission Docket R-362, reliability and adequacy of electric service, and Orders 383-2, 383-3, and 383-4. The Department of Energy, established in October 1977, assumed the responsibility for this activity. This form is considered voluntary under the authority of the Federal Power Act (Public Law 88-280), The Federal Energy Administration Act of 1974 (Public Law 93-275), and the Department of Energy Organization Act (Public Law 95-91). It is now under the jurisdiction of the Assistant Secretary for International Affairs and Energy Emergencies.

Data Processing. The Form IE-411 is filed annually on April 1 by the nine North American Electric Reliability Councils. The forms are compiled from data furnished by electric utilities within the council areas. Data from the Form IE-411 are also summarized in the staff report *Electric Power Supply and Demand for the Contiguous United States* (DOE/IE-0013).

Form IE-417R

Electric utilities or other entities, subject to the provisions of Section 311 of the Federal Power Act (FPA), that are engaged in the generation, transmission, or distribution of electric energy for delivery and/or sale to the public are required to report expeditiously any 1) loss of firm system loads; 2) voltage reductions and public appeals; 3) vulnerabilities that could impact bulk electric power system adequacy or reliability; and, 4) fuel supply emergencies to the DOE.

In accordance with Section 202(a) of the Federal Power Act (FPA), the DOE is responsible for encouraging actions to assure an abundant supply of electric energy throughout the country. Under Section 311 of the FPA, the DOE is authorized and directed to collect information regarding the generation, transmission, and distribution of electric energy and to report the problems and developments of the electric utility industry to Congress. The Secretary of Energy has the Federal responsibility of receiving reports of major electric utility system emergencies. The Secretary has delegated that responsibility to the Office of International Affairs and Energy Emergencies (IE) with the DOE.

Instrument and Design History. The collection of outage data was initiated by the FPC prior to the organization of the DOE. After Congress passed legislation creating the DOE, the collection of electric power system outage data became a function of the DOE. Currently the Assistant Secretary of IE is the principal DOE office for this activity. Form IE-417 was activated after public comment on a rule-making procedure (FR 7/6/83). The form was revised to Form IE-417R after public comment under a later rule-making procedure (FR 10/31/86).

Data Processing. Reports of emergencies are usually received by the Alert Coordination Officer via telephone. The Director, Office of Emergency Operations, has the authority to require a full technical report (after notice in the *Federal Register*).

Form FE-781R

The Form FE-781R, "Annual Report of International Electrical Export/Import Data" is used to collect on an annual basis, monthly information on the gross amounts of electrical energy received and delivered and the costs and revenue associated with these transactions. The use of the format contained in Form FE-781R is optional for reporting purposes; however, submission of the data is mandatory.

Instrument and Design History. The authority to issue presidential permits pursuant to Executive Order Number 10485 was transferred to the Secretary of Energy by Executive Order Number 12038 (43 FR 4957 February 7, 1987). This responsibility was delegated by the Secretary to the Economic Regulatory Administration (DOE Delegation Order Number 0204-04, October 1, 1977). The authority was redelegated (DOE Delegation Order Number 127) to the Office of Fuels Programs, Fossil Energy, (54 FR 11436 March 20, 1989). The survey universe is defined under Title 10 of the Code of Federal Regulations, Sections 205.308 and 205.325 to include all public utilities or other entities subject to the Department of Energy jurisdiction under Part II of the Federal Power Act engaged in the export of electric energy across the international borders of the United States with Canada and Mexico. It also includes those engaged in the transmission of electrical energy across these borders who hold a presidential permit.

Data Processing. The Form FE-781R is mailed to the respondents to collect annually, the monthly data for the preceding calendar year. The completed forms are to be returned to the DOE by February 15. The receipts are manually edited and the data used for the Presidential Permit Program are entered into a machine readable format.

Quality of Data

The Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF) is responsible for routine data improvement and quality assurance activities. All operations in this office are done in accordance with formal standards established by the EIA. These standards are the measuring rod necessary for quality statistics. Data improvement efforts include verification of data-keyed input by automatic computerized methods, editing by subject matter specialists, and follow up on nonrespondents. The CNEAF office supports the quality assurance efforts of the data collectors by providing advisory reviews of the structure of information requirements, and of proposed designs for new and revised data collection forms and systems. Once implemented, the actual performance of working data collection systems is also validated. Computerized respondent data files are checked to identify those who fail to respond to the survey. By law, nonrespondents may be fined or otherwise penalized for not filing a mandatory EIA data form. Before invoking the law, the EIA tries to obtain the required information by encouraging cooperation of nonrespondents.

Completed forms received by the CNEAF office are sorted, screened for completeness of reported information, and keyed onto computer tapes for storage and transfer to random access data bases for computer processing. The information coded on the computer tapes is manually spot-checked against the forms to certify accuracy of the tapes. To ensure the quality standards established by the EIA, formulas that use the past history of data values in the data base have been designed and implemented to check data input for errors auto-

matically. Data values that fall outside the ranges prescribed in the formulas are verified by telephoning respondents to resolve any discrepancies.

Conceptual problems affecting the quality of data are discussed in the report, *An Assessment of the Quality of Selected EIA Data Series: Electric Power Data.* This report is published by the Energy Information Administration (Office of Statistical Standards, see Appendix B).

Data Editing System

Data from the form surveys are edited using automated systems. The edit includes both deterministic checks, in which records are checked for the presence of required fields and their validity; and statistical checks, in which estimation techniques are used to validate data according to their behavior in the past and in comparison to other current fields.

Confidentiality of the Data

The data collected on the forms used for input to this report are not confidential.

Rounding Rules for Data

Given a number with r digits to the left of the decimal and d+t digits in the fraction part, with d being the place to which the number is to be rounded and t being the remaining digits which will be truncated, this number is rounded to r+d digits by adding 5 to the (r+d+1)th digit when the number is positive or by subtracting 5 when the number is negative. The t digits are then truncated at the (r+d+1)th digit. The symbol for a rounded number truncated to zero is (*).

Data Correction and Revision Procedures

The CNEAF office has adopted the following policy with respect to the revision and correction of data published in energy data reports and made available in a machine format:

1. All data collected by this office (excluding secondary source data) will be published as preliminary data when first appearing in an energy data report.
2. The next publication of the data will be in final form at which point the data base is closed.
3. Revisions or corrections will be made only in the event a substantial (greater than 1 percent) reporting change is received or a substantial (greater than 1 percent) error is discovered.
4. Revisions or corrections to published secondary source data will be made if and when the organization from which the data were received revises or corrects the data.
5. No revisions will be made without the approval of the Director, Electric Power Division.

The *Electric Power Annual* presents the most current annual data available to the EIA. The statistics may differ from those published previously in the *Electric Power Monthly* due to corrections, revisions, or other adjustments that may have been made to the data subsequent to the original monthly submissions (Table C1). Data for emissions from fossil-fueled steam-electric generating units in this publication have been revised to 1) include petroleum coke, 2) reflect refinements to the calculation methodology, and 3) rectify minor reporting errors. These revisions represent increases of 0.3 percent for sulfur dioxide, 2.5 percent for nitrogen oxides, and 0.2 percent for carbon dioxide at the national level. The sales of electricity to ultimate consumers, its associated revenue, and the number of ultimate consumers for 1988 have been revised for the States of Missouri and Alaska. These revisions represent a .04 and -.49 percent change in sales of electricity to ultimate consumers, a .03 and -.27 percent change in revenue, and a .04 and -.44 percent change in the number of ultimate consumers, respectively. Data for the average cost of coal have been revised to incorporate substantial revisions submitted by a respondent. These revisions represent an increase in the cost of coal delivered to the State of Georgia of 1.5 percent, to the South Atlantic Census Division of 0.3 percent, and at the national level of 0.1 percent.

Table C1. Comparison of Prior Versus Final Published Data at the National Level, 1989

Item	Prior	Final	Percent Change
Generation (gigawatthours)			
Coal	1,551,852	1,553,661	0.12
Petroleum	158,241	158,318	.05
Gas	264,957	266,598	.62
Hydroelectric	265,061	265,063	0
Nuclear	529,355	529,355	0
Other[1]	11,309	11,309	0
Consumption			
Coal (1,000 short tons)	765,820	766,888	.14
Petroleum (1,000 barrels)	266,836	267,451	.23
Gas (million cubic feet)	2,767,903	2,787,012	.69
Stocks[2]			
Coal (1,000 short tons)	135,894	135,860	-.03
Petroleum (1,000 barrels)	61,410	61,270	-.23
Receipts			
Coal (1,000 short tons)	753,217	753,217	0
Petroleum (1,000 barrels)	246,422	246,422	0
Gas (million cubic feet)	2,472,506	2,472,506	0
Average Cost (cents per million Btu)			
Coal	144.5	144.6	.07
Petroleum	289.3	289.3	0
Gas	235.5	235.5	0

[1] Includes geothermal, wood, wind, waste, and solar.
[2] Stocks are shown as of December 31 of each year.
Note: Percent change is calculated before rounding.
Sources: Energy Information Administration. **•Prior Generation, Consumption, and Stocks Data:** "Electric Power Monthly" DOE/EIA-0226(89/01-12). **•Prior Receipts and Costs Data:** *Cost and Quality of Fuels for Electric Utility Plants DOE/EIA-0191(89).* **•Final Generation, Consumption, and Stocks Data:** Form EIA-759, "Monthly Power Plant Report." **•Final Receipts and Costs Data:** Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

Formulas and Calculations

Average Heat Content

In order to determine the Btu value per unit of consumption (Table C2) for each of the fossil fuels collected on the Form EIA-759, the heat content values contained on the FERC Form 423 were used. Data on the FERC Form 423 represent 86 percent of the total generator nameplate capacity for all electric utilities.

Percent Difference

The following formula is used to calculate percent differences.

$$\text{Percent Difference} = \left(\frac{x(t_2) - x(t_1)}{x(t_1)} \right) \times 100,$$

where $x(t_1)$ and $x(t_2)$ denote the quantity at year t_1 and subsequent year t_2.

Form EIA-759

Data for the Form EIA-759 are collected at the plant level. These data are then aggregated to provide geographic totals at the State, Census division, and U.S. level, or totals by type of plant. Consumption of fuel(s) is converted from quantities (in short tons, barrels, or thousand cubic feet) to Btu at the plant level. End-of-month fuel stocks for a single generating plant may not equal beginning-of-the-month stocks, plus receipts, less consumption, for many reasons, including the fact that several plants may share the same fuel stock.

FERC Form 423

Data for the FERC Form 423 are collected at the plant level. These data are then used in the following formulas to produce aggregates and averages for each fuel type at the State, Census division, and U.S. level. For these formulas, receipts and average heat content are at the plant level. For each geographic region, the summation Σ represents the sum of all plants in that geographic region. Additionally,

- For coal, units for receipts (R) are in tons, units for average heat content (A) are in Btu per pound, and the unit conversion (U) is 2,000 pounds per ton;

Table C2. Average Heat Content of Fossil-Fuel Receipts by Census Division and State, 1989

Census Division and State	Coal (Btu per short ton)	Petroleum (Btu per barrel)	Gas (Btu per thousand cubic feet)
New England	**26,218,044**	**6,328,689**	**1,046,208**
Connecticut	26,615,582	6,304,453	1,030,215
Maine	NA	6,284,119	NA
Massachusetts	26,017,477	6,315,021	1,048,266
New Hampshire	26,718,178	6,545,581	NA
Rhode Island	NA	6,290,329	1,030,642
Vermont	NA	NA	NA
Middle Atlantic	**24,864,014**	**6,285,434**	**1,029,286**
New Jersey	26,638,102	6,239,041	1,033,054
New York	25,647,516	6,290,197	1,028,426
Pennsylvania	24,545,135	6,306,994	1,028,636
East North Central	**22,087,374**	**6,127,192**	**469,138**
Illinois	21,271,495	6,240,650	1,017,469
Indiana	21,396,816	5,752,695	1,002,345
Michigan	22,556,613	6,105,428	* 107,733
Ohio	23,669,293	6,090,817	1,007,202
Wisconsin	19,410,275	5,813,290	1,003,314
West North Central	**17,352,579**	**5,974,061**	**977,338**
Iowa	18,421,959	5,812,690	1,006,969
Kansas	17,751,368	5,831,309	970,654
Minnesota	17,534,440	5,775,537	1,004,789
Missouri	20,735,338	6,126,184	1,015,998
Nebraska	17,328,784	6,214,756	958,632
North Dakota	13,159,880	5,813,612	1,050,058
South Dakota	12,273,327	5,880,000	NA
South Atlantic	**24,843,275**	**6,297,413**	**1,016,305**
Delaware	25,886,954	6,321,044	1,074,537
District of Columbia	NA	6,012,213	NA
Florida	24,848,748	6,339,669	1,010,224
Georgia	24,199,475	5,847,247	1,022,524
Maryland	25,395,312	6,295,598	1,044,628
North Carolina	25,061,113	5,809,101	NA
South Carolina	25,235,238	5,797,479	1,022,781
Virginia	25,386,170	6,145,789	1,041,476
West Virginia	24,790,598	5,843,163	1,000,000
East South Central	**23,824,776**	**6,151,267**	**1,024,704**
Alabama	24,045,272	5,760,618	1,029,632
Kentucky	23,056,117	5,838,503	1,023,281
Mississippi	25,308,471	6,316,660	1,024,524
Tennessee	23,789,685	5,806,943	NA
West South Central	**15,384,166**	**6,009,613**	**1,036,350**
Arkansas	17,439,038	6,053,378	1,019,124
Louisiana	16,373,534	6,288,242	1,043,540
Oklahoma	17,823,470	5,765,188	1,042,707
Texas	14,573,339	5,945,532	1,034,341
Mountain	**19,541,200**	**6,069,149**	**1,029,855**
Arizona	21,192,712	5,934,775	1,035,128
Colorado	19,696,849	5,758,783	977,258
Idaho	NA	NA	NA
Montana	17,017,853	5,922,000	1,212,940
Nevada	22,233,071	6,228,826	1,027,390
New Mexico	18,257,018	5,859,260	1,033,341
Utah	22,644,414	5,881,050	NA
Wyoming	17,576,719	5,842,876	1,035,874
Pacific Contiguous	**16,438,624**	**6,147,611**	**1,039,503**
California	NA	6,147,970	1,039,503
Oregon	NA	5,873,178	NA
Washington	16,322,356	6,136,114	NA
Pacific Noncontiguous	**NA**	**6,245,783**	**NA**
Alaska	NA	NA	NA
Hawaii	NA	6,245,783	NA
U. S. Total	**20,850,185**	**6,280,947**	**1,027,938**

* Consists mostly of blast furnace gas, which has an average heat content of 85,472 Btu per thousand cubic feet. For further detailed information, see Table 37 of the "Electric Power Monthly."

NA = Not applicable.

Note: Totals may not equal sum of components because of independent rounding.

Source: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants."

- For petroleum, units for receipts (R) are in barrels, units for average heat content (A) are in Btu per gallon, and the unit conversion (U) is 42 gallons per barrel;
- For gas, units for receipts (R) are in thousand cubic feet (Mcf), average heat content (A) are in Btu per cubic foot, and the unit conversion (U) is 1,000 cubic feet per Mcf.

$$\text{Total Btu} = \sum_i (R_i \times A_i \times U),$$

where i denotes a plant; R_i = receipts for plant i; A_i = average heat content for receipts at plant i; and, U = unit conversion;

$$\text{Weighted Average Btu} = \frac{\sum_i (R_i \times A_i)}{\sum_i R_i},$$

where i denotes a plant; R_i = receipts for plant i; and, A_i = average heat content for receipts at plant i.

The weighted average cost in cents per million Btu is calculated using the following formula:

$$\text{Weighted Average Cost} = \frac{\sum_i (R_i \times A_i \times U \times C_i)}{\sum_i (R_i \times A_i)},$$

where i denotes a plant; R_i = receipts for plant i; A_i = average heat content for receipts at plant i; and, C_i = cost in cents per million Btu for plant i.

The weighted average cost in dollars per unit is calculated using the following formula:

$$\text{Weighted Average Cost} = \frac{U \sum_i (R_i \times A_i \times C_i)}{(10^8 \frac{cents}{dollar}) \sum_i R_i}$$

where i denotes a plant; R_i = receipts for plant i; A_i = average heat content for receipts at plant i; U = unit conversion; and, C_i = cost in cents per million Btu for plant i.

Form EIA-861

Data for the Form EIA-861 are collected at the utility level from all electric utilities in the United States, its territories, and Puerto Rico. Form EIA-861 data in this publication are for the United States only. These data are then aggregated to provide geographic totals at the State, NERC Region, Census division, and national level. Sources and disposition of data are also provided by utility class of ownership and retail consumer class of service. Average revenue per kilowatthour of electricity sold is calculated by dividing total annual retail revenue by the total annual retail sales of electricity.

Form EIA-860

Data for the Form EIA-860 are submitted at the generating unit level and are then aggregated to provide totals by energy source and geographic area. In addition, at the national level, data are aggregated by prime mover.

Estimated values for net summer and net winter capability for electric generating units were developed by use of a regression formula. Estimates of net summer capability and net winter capability are made for operable nonnuclear electric generating units with no reported capability and for all electric generating units that are under construction or in the planning stage that are not nuclear-powered or coal-fired. The formula is based on reported values in the 1984 data file. The formula is used to estimate values for existing units where data are missing and for projected units. In all formulas, the symbol, *, is an operator meaning multiplied by; the symbol, **, is an operator meaning raised to the specified power (exponent).

For nonnuclear units,

Net Summer Capability equals E**(i plus (ln(generator Nameplate Capacity)*c)), rounded to nearest megawatt,

where

- E, the base of natural logarithms (ln), is approximately 2.71828,
- Generator Nameplate Capacity is expressed in megawatts,
- i is the intercept, and c is the regression coefficient,
- i equals 0.02564, c equals 0.98423, for steam units (Unit Type is Steam Turbine - Boiler (ST)),
- i equals 0.10255, c equals 0.97841, for gas-turbine units (Unit Types are Gas Turbine (GT) and Jet Engine (JE)),
- i equals 0.00397, c equals 0.95914, for combined-cycle units (Unit Types are Combined Cycle Steam Turbine with Supplemental Firing (CA), Combined Cycle - Single Shaft (CS), Combined Cycle Steam Turbine with Only Waste Heat Capability (CW), and Combustion Cycle Combustion Turbine (CT)),
- i equals 0.08865, c equals 1.00966, for internal combustion units (Unit Type is Internal Combustion (diesel) (IC)),
- i equals 0.04963, c equals 1.03738 for conventional and pipeline hydroelectric units (Unit Types are Hydraulic Turbine (HC) and Hydraulic Turbine - Pipeline (HL)),

- i equals 0.00922, c equals 1.00630, for pumped storage hydroelectric units (Unit Type is Hydraulic Turbine - Reversible (pumped storage) (HR)),
- i equals 0.02604, c equals 0.98289, for all other units (Unit Types are Fuel Cell (FC), Steam Turbine - Geothermal (GE), Ocean Thermal Turbine (OC), Photovoltaic (SP), Steam Turbine - Solar (SS), and Wind Turbine (WT)).

Net Winter Capability equals (E**i)*(Generator Nameplate Capacity**c), rounded to nearest megawatt,

where

- E, the base of natural logarithms (ln), is approximately 2.71828,
- Generator Nameplate Capacity is expressed in megawatts for conventional hydroelectric and pipeline hydroelectric units, and in kilowatts for all other unit types,
- i is the intercept, and c is the regression coefficient,
- i equals 0.1614, c equals 0.98373, for steam units (Unit Type is ST),
- i equals 0.2249, c equals 0.97881, for gas-turbine units (Unit Types are GT and JE),
- i equals 0.9626, c equals 0.90413, for combined-cycle units (Unit Types are CA, CS, CW, and CT),
- i equals 0.1378, c equals 1.02501, for internal combustion units (Unit Type is IC),
- i equals 0.0608, c equals 1.02560, for conventional and pipeline hydroelectric units (Unit Types are HC and HL),
- i equals 0.1167, c equals 1.08540, for pumped storage hydroelectric units (Unit Type is HR),
- i equals 0.2859, c equals 0.96587, for all other units (Unit Types are FC, GE, OC, SP, SS, and WT).

Composite Financial Indicators for Selected Investor-Owned Electric Utilities

The following formulas are used to calculate composite financial indicators.

Electric Fixed Asset (Net Plant) Turnover =

$$\frac{\sum_i (EO_i)}{\sum_i (U_i)},$$

where EO_i is the Electric Operating Revenue for the i^{th} major utility, and U_i is the Electric Utility Plant -- Net for the i^{th} major utility.

Total Asset Turnover =

$$\frac{\sum_i (O_i)}{\sum_i (A_i)},$$

where O_i is the Operating Revenue for the i^{th} major utility, and A_i are the Total Assets for the i^{th} major utility.

Current Assets to Current Liabilities =

$$\frac{\sum_i (CAA_i)}{\sum_i (CAL_i)},$$

where CAA_i are the Current and Accrued Assets for the i^{th} major utility, and CAL_i are the Current and Accrued Liabilities for the i^{th} major utility.

Long-Term Debt to Capitalization =

$$\frac{\sum_i (LTD_i)}{\sum_i (C_i)} \times 100,$$

where LTD_i is the Long-term Debt for the i^{th} major utility, and C_i is the Capitalization for the i^{th} major utility.

Preferred Stock to Capitalization =

$$\frac{\sum_i (PS_i)}{\sum_i (C_i)} \times 100,$$

where PS_i is the Preferred Stock for the i^{th} major utility, and C_i is the Capitalization for the i^{th} major utility.

Common Stock Equity to Capitalization =

$$\frac{\sum_i (CSE_i)}{\sum_i (C_i)} \times 100,$$

where CSE_i is the Common Stock Equity of the i^{th} major utility; and, C_i is the Capitalization for the i^{th} major utility.

Total Debt to Total Assets =

$$\frac{\sum_i (LTD_i + STD_i)}{\sum_i (A_i)} \times 100,$$

where LTD_i is the Long-term Debt of the i^{th} major utility; STD_i is the Short-term Debt of the i^{th} major utility; and, A_i are the Total Assets of the i^{th} major utility.

Common Stock Equity to Total Assets =

$$\frac{\sum_i (CSE_i)}{\sum_i (A_i)} \times 100,$$

where CSE_i is the Common Stock Equity of the i^{th} major utility; and, A_i are the Total Assets of the i^{th} major utility.

Interest Coverage Before Taxes Without AFUDC =

$$\frac{\sum_i \left(\begin{matrix} IBI_i + EIT_i + GIT_i \\ + OUIT_i + TOID_i - AC_i \end{matrix} \right)}{\sum_i (IE_i)}$$

where IBI_i is Total Income Before Interest Charges for the i^{th} major utility; EIT_i are the Electric Income Taxes for the i^{th} major utility; GIT_i are the Gas Income Taxes for the i^{th} major utility; $OUIT_i$ are the Other Utility Income Taxes for the i^{th} major utility; $TOID_i$ are the Taxes for Other Income and Deductions for the i^{th} major utility; AC_i is the Allowance for Other Funds Used During Construction (AFUDC) for the i^{th} major utility; and, IE_i is the Interest Expense for the i^{th} major utility.

Profit Margin =

$$\frac{\sum_i (NI_i)}{\sum_i (O_i)} \times 100,$$

where NI_i is the Net Income of the i^{th} major utility; and, O_i is the Utility Operating Revenue for the i^{th} major utility.

Return on Average Common Stock Equity =

$$\frac{\sum_i (NI_i)}{\left(\sum_i (CSEB_i) + \sum_i (CSEE_i) \right)} / 2 \times 100,$$

where NI_i is the Net Income of the i^{th} major utility; $CSEB_i$ is the Common Stock Equity at Beginning of Year, for the i^{th} major utility, and $CSEE_i$ is the Common Stock Equity at End of Year for the i^{th} major utility.

Return on Investment =

$$\frac{\sum_i (NI_i)}{\sum_i (A_i)} \times 100,$$

where NI_i is the Net Income of the i^{th} major utility; and, A_i are the Total Assets of the i^{th} major utility.

Composite Financial Indicators for Selected Publicly Owned Electric Utilities

Electric Utility Plant per Dollar of Revenue =

$$\frac{\sum_i (EUP_i)}{\sum_i (EOR_i)},$$

where EUP is the Electric Utility Plant for the the i^{th} public utility; and, EOR is the Electric Operating Revenue for the i^{th} public utility.

Current Assets to Current Liabilities =

$$\frac{\sum_i (CA_i)}{\sum_i (CL_i)},$$

where CA_i are the Current and Accrued Assets for the i^{th} public utility; and, CL_i are the Current and Accrued Liabilities for the i^{th} public utility.

Electric Utility Plant as a Percent of Total Assets =

$$\frac{\sum_i (EUP_i)}{\sum_i (TA_i)} \times 100,$$

where EUP_i is the Electric Utility Plant for the i^{th} public utility; and, TA_i are the Total Assets for the i^{th} public utility.

Net Electric Utility Plant as a Percent of Total Assets =

$$\frac{\sum_i (NEUP_i)}{\sum_i (TA_i)} \times 100,$$

where $NEUP_i$ is the Net Electric Utility Plant for the i^{th} public utility; and, TA_i is the Total Assets for the i^{th} public utility.

Accumulated Provision for Depreciation as a Percent of Electric Utility Plant =

$$\frac{\sum_i (APD_i)}{\sum_i (EUP_i)} \times 100,$$

where APD_i is the Accumulated Provision for Depreciation for the i^{th} public utility; and, EUP_i is the Electric Utility Plant for the i^{th} public utility.

Electric Operation and Maintenance Expenses as a Percent of Electric Operating Revenue =

$$\frac{\sum_i (EOME_i)}{\sum_i (EOR_i)} \times 100,$$

where $EOME_i$ is the Electric Operation and Maintenance Expenses for the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Electric Depreciation and Amortization as a Percent of Electric Operating Revenue =

$$\frac{\sum_i (EDA_i)}{\sum_i (EOR_i)} \times 100,$$

where EDA_i is Electric Depreciation and Amortization for the i^{th} public utility; and, EOP_i is the Electric Operating Revenue for the i^{th} public utility.

Taxes and Tax Equivalents as a Percent of Electric Operating Revenue =

$$\frac{\sum_i (TTE_i)}{\sum_i (EOR_i)} \times 100,$$

where TTE_i are the Taxes and Tax Equivalents for the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Net Contributions and Services as a Percent of Electric Operating Revenue =

$$\frac{\sum_i (CS_i)}{\sum_i (EOR_i)} \times 100,$$

where CS_i are the Net Contributions and Services for the i^{th} public utility; and EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Interest Expense as a Percent of Electric Operating Revenue =

$$\frac{\sum_i (IE_i)}{\sum_i (EOR_i)} \times 100,$$

where IE_i is the Interest Expense for the i^{th} public utility; and, EOR_i is the Electric Operating Revenue for the i^{th} public utility.

Form EIA-767

This section describes the methodology employed to calculate estimates of sulfur dioxide, nitrogen oxide, and carbon dioxide emissions using information contained on Form EIA-767. The methodology used to calculate estimates of emissions has been verified by comparing the emissions data presented in this report with the National Acid Precipitation Assessment Program (NAPAP) data.

Uncontrolled Air Pollutant Emissions. Uncontrolled air pollutant emissions are those emissions that would occur in the absence of any control equipment. Uncontrolled sulfur dioxide, nitrogen oxide, and carbon dioxide emissions are determined by multiplying the quantity of fuel burned by an emission factor. An emission factor is the average quantity of pollutant released from a boiler when a unit of fuel is burned.

The source of both the sulfur dioxide and nitrogen oxides emission factors is the Environmental Protection Agency report, *Compilation of Air Pollutant Emission Factors*.[31] Environmental Protection Agency emission factors are based on boiler type and fuel burned. The Environmental Protection Agency emission factors are used in Table C3. Emission factors for carbon dioxide were estimated by the Electric Power Division of the EIA. Emissions of carbon dioxide are generally a function of the amount of carbon in the fuel. Emission factors were estimated for fuel type independent of boiler type.

Uncontrolled emissions of sulfur dioxide and nitrogen oxides do not accurately depict the quantity of emissions released into the atmosphere because they fail to

[31]Environmental Protection Agency, Office of Air and Radiation, *Supplement A to Compilation of Air Pollutant Emission Factors, Vol. I: Stationary Point and Area Sources*, AP-42 (Research Triangle Park, North Carolina, October 1986).

Table C3. Sulfur Dioxide, Nitrogen Oxide, and Carbon Dioxide Emission Factors

Fuel	Boiler Type[1]	Factors		
		Sulfur Dioxide[2]	Nitrogen Oxides[3]	Carbon Dioxide
Coal[4]		**lbs per ton**	**lbs per ton**	**lbs per 10^6 Btu**
Bituminous	Pulverized Coal--Dry Bottom	39xS	21(15)	209
	Pulverized Coal--Wet Bottom	39xS	34	209
	Cyclone	39xS	37	209
	Spreader Stoker	39xS	14	209
	All Others	39xS	7.5	209
Subbituminous	Pulverized Coal--Dry Bottom	35xS	21(15)	219
	Pulverized Coal--Wet Bottom	35xS	34	219
	Cyclone	35xS	37	219
	Spreader Stoker	35xS	14	219
Anthracite	Pulverized Coal	39xS	18	209
	Stoker	39xS	10	209
Lignite	Pulverized Coal--Front Wall/Opposed Firing	30xS	14	213
	Pulverized Coal--Tangential	30xS	8	213
	Pulverized Coal--All Others	30xS	12	213
	Cyclone	30xS	17	213
	All Others	30xS	6	213
Petroleum		**lbs per 10^3 gal**	**lbs per 10^3 gal**	**lbs per 10^6 Btu**
Residual Heavy Oil	Tangentially Fired	159.9xS	42	180
	Vertically Fired	159.9xS	105	180
	All Others	159.9xS	67	180
Light Distillate	All	144.0xS	20	156
Natural Gas		**lbs per 10^6 cf**	**lbs per 10^6 cf**	**lbs per 10^6 Btu**
	Tangentially Fired	0.6	275	120
	All Others	0.6	550	120

[1] See the Environmental Protection Agency report for definitions of boiler types.
[2] "xS" indicates that the constant must be multiplied by the percentage (by weight) of sulfur in the fuel. Sulfur dioxide emission factors also account for small quantities of sulfur trioxide and gaseous sulfates.
[3] Parenthetic value is for tangentially fired boilers. Tangentially fired boilers are fired from the corners of the furnace and are capable of directing the fireball in an upward or downward direction.
[4] Coal types are categorized by Btu content in this table as follows: Bituminous (equal to or greater than 9,750 Btu per pound), Subbituminous (equal to 7,500 to 9,750 Btu per pound), and Lignite (less than 7,500 Btu per pound).
cf = Cubic Feet.
gal = U.S. Gallons.
lbs = Pounds.
Source: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors*, Volume 1, AP-42(October 1986).

reflect reductions prompted by emission standards. Consequently, controlled emissions are calculated to provide a more accurate estimate of actual emissions.

Controlled Sulfur Dioxide Emissions. Because of regulations controlling sulfur dioxide emissions, many utilities are required to install flue gas desulfurization (FGD) units at their coal-fired plants.[32] FGD units typically remove between 70 and 90 percent of sulfur dioxide emissions. However, it is assumed that utilities operate them only to the degree necessary to meet the most stringent standard that they face. All utilities are required to comply with Federal standards, and some may also be required to comply with State and local standards. State and local standards may be more or less strict than Federal standards. In this study it is assumed that all utilities comply with the most stringent standard that they encounter. Accordingly, controlled sulfur dioxide emissions for each plant are calculated by subtracting the amount that it is required to remove in order to comply with its most stringent emission standard from its uncontrolled emissions level.

In order to calculate controlled sulfur dioxide emissions, plants are divided into five categories depending on whether their most stringent emission standard is: (1) more strict than 1978 Revised New Source Performance Standards (RNSPS); (2) equal to 1978 RNSPS; (3) less strict than 1978 RNSPS but more strict than 1971 NSPS; (4) equal to 1971 New Source Performance Standards (NSPS); or (5) less strict than 1971 NSPS. Plants built prior to 1971 are not required to comply

[32] Flue gas desulfurization units may also remove sulfur dioxide emissions from plants that burn both coal and oil.

with either standard and therefore face only State and local requirements. These standards are reported on Form EIA-767. Plants built after August 17, 1971, but on or before September 18, 1978, must meet 1971 NSPS. Plants built after September 18, 1978, must meet 1978 RNSPS. Even if a plant is required to comply with NSPS or RNSPS, it still may face State or local standards.

The 1971 NSPS require all plants built after August 17, 1971, to emit no more than 1.2 pounds of sulfur dioxide per million Btu of heat input. Utilities are allowed to meet this standard by either burning low-sulfur coal or using FGD units. The 1978 RNSPS are more complex. All plants built after September 18, 1978, are required to use FGD units. If they burn coal that has a sulfur content per million Btu (1) less than 1 pound, they must remove 70 percent of the sulfur dioxide; (2) between 1 and 3 pounds, they must remove the amount (between 70 and 90 percent) that yields a sulfur dioxide emission rate of 0.6 pounds per million Btu; (3) between 3 and 6 pounds, they must remove 90 percent; and (4) greater then 6 pounds they must remove the amount that yields a sulfur dioxide emission rate of 1.2 pounds per million Btu.

Under the law, utilities are permitted to take credit for sulfur that remains in bottom ash (ash remaining in the bottom of the furnace after the coal is burned). For example, if a utility is required to remove 90 percent of the sulfur in the coal and 3 percent remains in the ash, it has to remove only 87 percent using scrubbers. This credit is included in emissions data in this report. It is likely, however, that in many cases the credit is not taken. In order to take the ash credit, utilities need to monitor the coal consumed on a daily basis; this is both time-consuming and costly. To the extent that utilities do not take the ash credit, emissions might be slightly overstated.

Controlled Nitrogen Oxide Emissions. Although there are many techniques that utilities can use to reduce their emissions of nitrogen oxides, it is impractical to calculate the actual reductions achieved.[33] Consequently, two assumptions are made to determine estimates for controlled emissions of nitrogen oxides: all boilers subject to a standard for emissions of nitrogen oxides will emit at a rate equal to the standard; and all boilers that are not subject to a standard will emit the quantity of nitrogen oxides determined by using the emission factors of the Environmental Protection Agency. Accordingly, controlled emissions of nitrogen oxides are determined by choosing the lesser of two numbers: the emission standard or the uncontrolled emission rate.

A degree of complexity is added to this approach, however, because emission standards are not reported in consistent units. In some rare instances emission standards are reported in units that cannot be directly compared with estimated uncontrolled emission rates. Examples of such standards are ones that specify the concentration of nitrogen oxides allowed in the stack gas or the ambient quality concentration of nitrogen oxides (parts per million). In cases where these types of standards were reported, the uncontrolled emission rate was used. Such standards are very rare, however, and do not significantly affect the results.

Table C4. Unit-of-Measure Equivalents

Unit	Equivalent		
Kilowatt (kW)	1,000	(One Thousand)	Watts
Megawatt (MW)	1,000,000	(One Million)	Watts
Gigawatt (GW)	1,000,000,000	(One Billion)	Watts
Terawatt (TW)	1,000,000,000,000	(One Trillion)	Watts
Gigawatt	1,000,000	(One Million)	Kilowatts
Thousand Gigawatts	1,000,000,000	(One Billion)	Kilowatts
Kilowatthours (kWh)	1,000	(One Thousand)	Watthours
Megawatthours (MWh)	1,000,000	(One Million)	Watthours
Gigawatthours (GWh)	1,000,000,000	(One Billion)	Watthours
Terawatthours (TWh)	1,000,000,000,000	(One Trillion)	Watthours
Gigawatthours	1,000,000	(One Million)	Kilowatthours
Thousand Gigawatthours	1,000,000,000	(One Billion)	Kilowatthours
U.S. Dollar	1,000	(One Thousand)	Mills
U.S. Cent	10	(Ten)	Mills

Source: Energy Information Administration, Electric Power Division.

[33]Emissions of nitrogen oxides are highly sensitive to many operating parameters that are not easily monitored.

General Information

Use of the Glossary

The terms in the glossary have been defined for general use. Restrictions on the definitions as used in these data collection systems are included in each definition when necessary to define the terms as they are used in this report.

Obtaining Copies of Data

Upon EIA approval of the *Electric Power Annual*, the data are available for public use on a cost-recovery basis.

Computer listings are obtained for a charge by submitting a written request to:

Energy Information Administration, EI-541
Electric Power Division
1000 Independence Avenue
Washington, DC 20585

These data are also available monthly on machine-readable tapes. Tapes may be purchased by using Visa, MasterCard, or American Express cards as well as money orders or checks payable to the National Technical Information Service (NTIS). Purchasers may also use NTIS and Government Printing Office depository accounts. To place an order, contact:

National Technical Information Service (NTIS)
Office of Data Base Services
U.S. Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161
(703) 487-4650

Glossary

Acid Rain: Also called acid precipitation or acid deposition, acid rain is precipitation containing harmful amounts of nitric and sulfuric acids formed primarily by nitrogen oxides and sulfur oxides released to the atmosphere when fossil fuels are burned. It can be wet precipitation (rain, snow, or fog) or dry precipitation (absorbed gaseous and particulate matter, aerosol particles or dust). Acid rain has a pH below 5.6. Normal rain has a pH of about 5.6, which is slightly acidic. The term pH is a measure of acidity or alkalinity and ranges from 0 to 14. A pH measurement of 7 is regarded as neutral. Measurements below 7 indicate increased acidity, while those above indicate increased alkalinity.

Allowance for Funds Used During Construction (AFUDC): A noncash item representing the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

Ampere: The unit of measurement of electrical current produced in a circuit by 1 volt acting through a resistance of 1 ohm. (See Current, Ohm, Volt.)

Anthracite: Anthracite, or hard coal, is the highest rank of economically useable coal. It is jet black with a high luster. The moisture content generally is less than 15 percent. Anthracite contains approximately 22 to 28 million Btu per ton as received and averages about 25 million Btu per ton. Its ignition temperature is approximately 925 to 970 degrees Fahrenheit. Virtually all of the anthracite mined is from northeastern Pennsylvania. It is used mostly for space heating and generating electricity.

Ash: Impurities consisting of silica, iron, alumina, and other incombustible matter which are contained in coal. Ash increases the weight of coal, adds to the cost of handling, and can affect the burning characteristics. Ash content is measured as a percent by weight of coal on an "as received" or a "dry" (moisture-free, usually part of a laboratory analysis) basis.

Asset: An economic resource that is tangible or intangible and which is expected to provide benefits to a business.

Available but not Needed Capability: Net capability of main generating units that are operable but not considered necessary to carry load, and cannot be connected to load within 30 minutes. (See Capability, Standby Facility.)

Bbl: The abbreviation for barrel. (See Barrel.)

Bcf: The abbreviation for one billion cubic feet.

Barrel: A volumetric unit of measure for crude oil and petroleum products equivalent to 42 U.S. gallons.

Base Bill: A charge calculated by taking the rate from the appropriate electric rate schedule and applying it to the level of consumption. (See Electric Rate Schedule.)

Baseload: The minimum amount of electric power delivered or required over a given period of time at a steady state. (See Baseload Plant.)

Baseload Capacity: The generating equipment normally operated to serve loads on an around-the-clock basis. (See Baseload, Baseload Plant.)

Baseload Plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechan-

ical and thermal efficiency and minimize system operating costs. (See Baseload.)

Bituminous Coal: Bituminous coal, or soft coal, is the most common coal. It is dense, black, often with well-defined bands of bright and dull material. Its moisture content usually is less than 20 percent. The heating value ranges from 19 to 30 million Btu per ton as received and averages about 24 million Btu per ton. The ignition temperature ranges from about 700 to almost 900 degrees Fahrenheit. Bituminous coal is mined chiefly in the Appalachian and Interior coal fields. It is used for generating electricity, making coke, and space heating.

Boiler: A device for generating steam for power, processing, or heating purposes; or hot water for heating purposes or hot water supply. Heat from an external combustion source is transmitted to a fluid contained within the tubes found in the boiler shell. This fluid is delivered to an end-use at a desired pressure, temperature and quality. (See Prime Mover.)

Btu (British Thermal Unit): A standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

Capability: The maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time without exceeding approved limits of temperature and stress.

Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer. (See Generator Nameplate Capacity.)

Capacity Charge: An element in a two-part pricing method used in capacity transactions (energy charge is the other element). The capacity (demand) charge is assessed on the amount of capacity being purchased. Also called Demand Charge.

Capital (Financial): The line items on the right side of a balance sheet, which include debt, preferred stock, and common equity. A net increase in assets must be financed by an increase in one or more forms of capital.

Census Divisions: The nine geographic divisions of the United States established by the Bureau of the Census, U.S. Department of Commerce for statistical analysis. The boundaries of Census divisions coincide with State boundaries. The Pacific Division is subdivided into the Pacific Contiguous and Pacific Noncontiguous areas.

Circuit: A conductor or a system of conductors through which electric current flows. (See Current.)

Coal: A black or brownish-black solid combustible substance formed by the partial decomposition of vegetable matter without access to air. The rank of coal, which includes anthracite, bituminous coal, subbituminous coal, and lignite, is based on fixed carbon, volatile matter, and heating value. Coal rank indicates the progressive alteration from lignite to anthracite. Lignite contains approximately 9 to 17 million Btu per ton. The contents of subbituminous and bituminous coal range from 16 to 24 million Btu per ton and from 19 to 30 million Btu per ton, respectively. Anthracite contains approximately 22 to 28 million Btu per ton. (See anthracite, bituminous coal, subbituminous coal, lignite)

Cogenerator: A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes.

Coincident Demand: The sum of two or more demands that occur in the same time interval. (See Demand.)

Coincident Peak Load: The sum of two or more peak loads that occur in the same time interval. (See Peak Load.)

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Combined Pumped-Storage Plant: A pumped-storage hydroelectric power plant that uses both pumped water and natural streamflow to produce electricity.

Commercial Operation: Commercial operation begins when control of the loading of the generator is turned over to the system dispatcher.

Commercial Retail Prices of Electricity: The price of electricity supplied to commercial or business establishments such as stores, offices, restaurants, and garages for lighting and other power purposes.

Commercial Sector: The commercial sector is generally defined as nonmanufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, and health, social, and educational institutions. Utilities may classify commercial service as including all consumers whose demand or annual use exceeds some specified limit. The limit may be set by the utility based on the rate schedule of the utility.

Construction Work In Progress (CWIP): The balance shown on a utility's balance sheet for construction work not yet completed but in progress. This balance line item may or may not be included in the rate base.

Consumption (Fuel): The amount of fuel used for gross generation, providing standby service and start-up and/or flame stabilization. (See Fuel.)

Contract Cost: Price of fuels marketed on a contract basis covering a period of 1 or more years. Contract prices reflect market conditions at the time the contract was negotiated and therefore remain constant throughout the life of the contract or are adjusted through escalation clauses. Generally, contract prices do not fluctuate widely.

Contract Receipts: Purchases based on a negotiated agreement that generally covers a period of 1 or more years.

Cooperative (Cooperatively Owned Electric Utility): A group organized under the law into a utility company that will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from the Federal income tax laws. Most cooperatives have initially been financed by the U.S. Department of Agriculture's Rural Electrification Administration. (See Electric Power Industry.)

Cost: The amount paid to acquire resources such as plant and equipment, fuel, or labor services.

Current (Electric): A flow of electrons in an electrical conductor. The strength or rate of movement of the electricity is measured in amperes. (See Ampere, Ohm, Volt.)

Demand (Electric): The rate at which electric energy is delivered to or by a system, part of a system, or piece of equipment, at a given instant or averaged over any designated period of time.

Distillate Fuel Oil: A general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating, on-and-off-highway diesel engine fuel (including railroad engine fuel and fuel for agriculture machinery), and electric power generation. Included are products known as No. 1, No. 2, and No. 4 fuel oils; No. 1, No. 2, and No. 4 diesel fuels.

Distribution System: The portion of an electric system that is dedicated to delivering electric energy to an end-user. (See System (Electric), Transmission.)

Diversity Exchange: An exchange of capacity or energy, or both, between systems whose peak loads occur at different times.

Electric Plant: A facility containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.

Electric Rate Schedule: A statement of the electric rate and the terms and conditions governing its application, including attendant contract terms and conditions that have been accepted by a regulatory body with appropriate oversight authority.

Electric Utility: An enterprise that is engaged in the generation, transmission, or distribution of electric energy primarily for use by the public and is the major power supplier within a designated service area. Electric utilities include publicly owned; cooperatively owned; and government-owned (municipals, Federal agencies, State projects, and public power districts) systems.

Energy: The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatthours, while heat energy is usually measured in British thermal units. (See Energy Source.)

Energy Charge: That portion of the charge for electric service based upon the electric energy (kWh) consumed or billed.

Energy Deliveries: Energy generated by one electric utility system and delivered to another system through one or more transmission lines. (See Wheeling Service.)

Energy Receipts: Energy generated by one electric utility system and received by another system through one or more transmission lines. (See Wheeling Service.)

Energy Source: The primary source that provides the power that is converted to electricity through chemical, mechanical, or other means. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Equity Capital: The sum of capital from retained earnings and the issuance of stocks.

Expenditure: The incurrence of a liability to obtain an asset or service.

Facility: A location at which prime movers, electric generators, and/or equipment for converting mechanical, chemical, and/or nuclear energy into electric energy are situated. A facility may contain more than one type of prime mover. For cogenerators, the facility includes the industrial or commercial process.

Federal Energy Regulatory Commission (FERC): FERC is a quasi-independent regulatory agency within the Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

Federal Power Act: Enacted in 1920, and amended in 1935, the Act consists of three parts. The first part incorporated the Federal Water Power Act administered by the former Federal Power Commission, whose activities were confined almost entirely to licensing non-Federal hydroelectric projects. Parts II and III were added with the passage of the Public Utility Act. These parts extended the Act's jurisdiction to include regulating the interstate transmission of electrical energy and rates for its sale as wholesale in interstate commerce. The Federal Energy Regulatory Commission is now charged with the administration of this law. (See Federal Energy Regulatory Commission).

Federal Power Commission: The predecessor agency of the Federal Energy Regulatory Commission. The Federal Power Commission was created by an Act of Congress under the Federal Water Power Act on June 10, 1920. It was charged originally with regulating the electric power and natural gas industries. It was abolished on September 30, 1977, when the Department of Energy was created. Its functions were divided between the Department of Energy and the Federal Energy Regulatory Commission. (See Federal Energy Regulatory Commission.)

FERC: The Federal Energy Regulatory Commission.

FERC Form 1: The "The Annual Report of Major Electric Utilities, Licensees and Others," collects financial and operational information from major privately owned electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. Approximately 180 electric utilities submit this form based on sales and transmission service (for each of the 3 previous calendar years) exceeding one of the following thresholds: 1 million megawatthours of total annual sales, 100 megawatthours of annual sales for resale, 500 megawatthours of annual gross interchange out, or 500 megawatthours of wheeling for others (deliveries plus losses).

FERC Form 423: The "Monthly Report of Cost and Quality of Fuels for Electric Plants," collects data on the cost, quality, and sources of fuel. Approximately 225 electric utilities report for each plant having a

fossil-fueled steam-electric nameplate capacity of 50 or more megawatts.

Firm Gas: Gas sold on a continuous and generally long-term contract.

Flue Gas Particulate Collectors: Equipment used to remove fly ash from the combustion gases of a boiler plant before discharge to the atmosphere. Particulate collectors include electrostatic precipitators, mechanical collectors (cyclones), fabric filters (baghouses), and wet scrubbers.

Flue Gas Desulfurization Unit (Scrubber): Equipment used to remove sulfur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals such as lime are used as the scrubbing media.

Forced Outage: The shutdown of a generating unit, transmission line or other facility, for emergency reasons or a condition in which the generating equipment is unavailable for load due to unanticipated breakdown.

Form EIA-759: The "Monthly Power Plant Report," collects monthly data from all electric utilities on net generation, consumption of coal, oil, and gas, and end-of-month stocks of coal and oil for each plant by prime mover and fuel-type combination. Approximately 800 electric utilities report. Form EIA-759 replaced the FPC Form 4 in January 1982.

Form EIA-767: The "Steam Electric Plant Operation and Design Report," collects data annually on plant operations and equipment design including boiler, generator, cooling system flue gas desulfurization, flue gas particulate collector, and stack data. Respondents are required to report for all plants with a fossil-fueled steam-electric nameplate capacity of 10 or more megawatts. Approximately 900 plants report. Form EIA-767 replaced the FPC Form 67 in 1982.

Form EIA-826: The "Monthly Electric Utility Sales and Revenue Report with State Distributions," collects monthly data on customers, sales, revenues, sales for resale, and other financial items. Approximately 225 electric utilities report.

Form EIA-860: The "The Annual Electric Generator Report," collects data from electric utilities in the United States on the status of electric power plants and associated equipment in operation within 10 years of the reporting year. Generator-specific data are reported by approximately 900 electric utilities.

Form EIA-861: The "The Annual Electric Utility Report," collects data on the source and disposition of energy, including net purchases, exchanges and wheeling, energy used by the electric department, energy furnished without charge, and energy losses, revenue, retail sales, sales for resale, and nonutility power production data. Form EIA-861 is a mandatory collection of data, filed annually by approximately 3,250 electric utilities in the United States, its territories, and Puerto Rico.

Fossil Fuel: Any naturally occurring organic fuel, such as petroleum, coal, and natural gas.

Fossil Fuel Plant: A plant using coal, petroleum, or gas as its source of energy.

Fuel: Any substance that can be burned to produce heat; also, materials that can be fissioned in a chain reaction to produce heat.

Fuel Expenses: These costs include the fuel used in the production of steam or driving another prime mover for the generation of electricity. Other associated expenses include unloading the shipped fuel, and all handling of the fuel up to the point where it enters the first bunker, hopper, bucket, tank, or holder in the boiler-house structure.

Full-Forced Outage: The net capability of main generating units that is unavailable for load for emergency reasons. (See Forced Outage, Standby Facility.)

Gas: (See Natural Gas.)

Gas Turbine Plant: A plant in which the prime mover is a gas turbine. A gas turbine consists typically of an axial-flow air compressor, one or more combustion chambers where liquid or gaseous fuel is burned and the hot gases are passed to the turbine; where the hot gases expand to drive the generator and then are used to run the compressor.

Generating Unit: Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

Generation: The process of producing electric energy by transforming other forms of energy; also, the amount of electric energy produced. (See Electric Plant, Energy.)

Generator: A machine that converts mechanical energy into electrical energy.

Generator Nameplate Capacity: The full-load continuous rating of a generator, prime mover, or other electrical power production equipment under specified conditions as designated by the manufacture. Installed generator nameplate rating is usually indicated on a nameplate physically attached to the generator.

Geothermal Plant: A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam that derives its energy from heat found in rocks or fluids at various depths beneath the surface of the earth. The energy is extracted by drilling and/or pumping.

Gigawatt (GW): One billion watts. (See Watt.)

Gigawatthour (GWh): One billion watthours. (See Watthour.)

Greenhouse Effect: The increasing mean global surface temperature of the earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbons). The greenhouse effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

Grid: The layout of an electrical distribution system. (See Transmission, Transmission System, Electric)

Gross Generation:. The total amount of electric energy produced by a generating facility as measured at the generator terminals. (See Generation, Electric Plant.)

Heavy Oil: The fuel oils remaining after the lighter oils have been distilled off during the refining process. Except for start-up and flame stabilization, virtually all petroleum used in steam plants is heavy oil.

Hydroelectric Plant: A plant in which the turbine generators are driven by falling water.

Industrial Retail Prices of Electricity: Price of the electricity supplied to industrial establishments such as automotive and steel producing industries.

Industrial Sector (Electricity): The industrial sector is generally defined as including manufacturing, construction, mining, agriculture, fishing, and forestry establishments Standard Industrial classified under Standard Industrial Classification (SIC) codes 01-39. The utility may classify industrial service using the SIC codes, or based on demand or annual usage exceeding some specified limit. The limit may be set by the utility based on its own rate schedule. Sales for consumers (i.e. farms and irrigation) that the utility has no system for separating into residential, commercial, and industrial classifications, should be classified based on the classification of consumer their rate most closely resembles. If there is no rate schedule distinction, utilities may define industrial consumers as those having a demand equal to or greater than 1,000 kilowatts.

Interdepartmental Service: Electricity supplied to departments of the electric utility company other than the electric generating department.

Intermediate Load: The range from base load to a point between base load and maximum peak. This point, which is dependent on the load curve, may be the midpoint, a percent of the peak load, or the load over a specified time period.

Internal Combustion Plant: A plant in which the prime mover is an internal combustion engine. An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal types used in electric plants. The plant is usually operated during periods of high demand for electricity.

Interruptible Gas: Gas sold to customers with a provision that permits curtailment or cessation of service and at the discretion of the distributing company under certain circumstances as specified in the service contract.

Kilowatt (kW): One thousand watts. (See Watt.)

Kilowatthour (kWh): One thousand watthours. (See Watthour.)

Leverage Ratio: The ratio of total debt to total assets.

Liability: An amount payable in dollars or by future services to be rendered.

Light Oil: Lighter fuel oils distilled off during the refining process. Virtually all petroleum used in internal combustion and gas-turbine engines is light oil.

Lignite: Lignite, the lowest rank of coal, is brownish black and has a high moisture content, sometimes as high as 45 percent. It tends to disintegrate when exposed to the weather. The heat content of lignite ranges from 9 to 17 million Btu per ton as received and averages about 14 million Btu per ton. The ignition temperature is approximately 600 degrees Fahrenheit. Lignite is mined in California, Louisiana, Montana, North Dakota, and Texas, and is used mainly to generate electricity in power plants that are relatively close to the mines.

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the customers.

Maximum Demand: The greatest of all demands of the load that has occurred within a specified period of time.

Mcf: One thousand cubic feet.

Megawatt (MW): One million watts. (See Watt.)

Megawatthour (MWh): One million watthours. (See Watthour.)

MMcf: One million cubic feet.

Natural Gas: A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in porous geological formations beneath the earth's surface, often in association with petroleum. The principal constituent is methane.

Net Generation: Gross generation less plant use, measured at the high-voltage terminals of the station's step-up transformer. The energy required for pumping at pumped-storage plants is regarded as plant use and must be deducted from the gross generation. (See Generation, Electric Plant.)

Net Summer Capability: The steady hourly output which generating equipment is expected to supply to system load exclusive of auxiliary power as demonstrated by tests at the time during summer peak demand.

Net Winter Capability: The steady hourly output which generating equipment is expected to supply to system load exclusive of auxiliary power as demonstrated by test at the time of winter peak demand.

Noncoincident Peak Load: The sum of two or more peak loads on individual systems that do not occur in the same time interval. Meaningful only when considering loads within a limited period of time, such as a day, week, month, a heating or cooling season, and usually for not more than 1 year.

Nonutility Power Producer: An enterprise that has electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area, and which are not otherwise required to file forms listed in the Code of Federal Regulations, Title 18, Part 141.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of nine regional reliability councils and encompasses essentially all the power systems of the contiguous United States, Canada, and some in Mexico. The NERC Regions are:

ECAR - East Central Area Reliability Coordination Agreement

ERCOT - Electric Reliability Council of Texas

MAIN - Mid-America Interconnected Network

MAAC - Mid-Atlantic Area Council

MAPP - Mid-Continent Area Power Pool

NPCC - Northeast Power Coordinating Council

SERC - Southeastern Electric Reliability Council

SPP - Southwest Power Pool

WSCC - Western Systems Coordinating Council

Nuclear Fuel: Fissionable materials that have been enriched to such a composition that when placed in a nuclear reactor will support a self-sustaining fission chain reaction, producing heat in a controlled manner for process use.

Nuclear Power Plant: A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced by a heat transfer from the reactor vessel during the period when the nuclear fuel is undergoing fission.

Off-Peak Gas: Gas which is to be delivered and taken on demand when demand is not at its peak. (See Spot Purchases.)

Ohm: The unit of measurement of electrical resistance. The resistance of a circuit in which a potential difference of one volt produces a current of one ampere. (See Ampere, Current, Volt.)

Operable: A unit is operable when it is available to provide power to the grid. For a nuclear unit, this is when it receives its full power amendment to its operating license from the Nuclear Regulatory Commission.

Other Service to Public Authorities: Electricity supplied to municipalities or divisions or agencies of State or Federal governments, under special contracts or agreements or service classifications applicable only to public authorities.

Outage: The period during which a generating unit, transmission line, or other facility is out of service. (See Forced Outage, Scheduled Outage.)

Peak Load: The maximum load during a specified period of time.

Peak Load Plant: A plant usually housing old, low-efficiency steam units; gas turbines; diesels; or pumped-storage hydroelectric equipment normally used during the peak-load periods.

Peaking Capacity: Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on an around-the-clock basis. (See Peak Load.)

Percent Difference: The relative change in a quantity over a specified time period. It is calculated as follows: The current value number has the previous value number subtracted from it, and this new number is divided by the absolute value of the previous value number; then this new number is multiplied by 100.

Petroleum: A mixture of hydrocarbons existing in the liquid state found in natural underground reservoirs, often associated with gas. Petroleum includes Fuel Oil 2, 4, 5, 6, topped crude, kerosene, and jet fuel. (See Petroleum (Crude Oil.))

Petroleum Coke: A residue, high in carbon content and low in hydrogen, that is the final product of thermal decomposition in the condensation process in cracking. This product is reported as marketable coke or catalyst coke. The conversion factor is 5 barrels (of 42 U.S. gallons each) per short ton.

Petroleum (Crude Oil): A naturally occurring, oily, flammable liquid composed principally of hydrocarbons. Crude oil is occasionally found in springs or pools but usually is drilled from wells beneath the earth's surface.

Plant Use: The electric energy used in the operation of a plant. Included in this definition is the energy required for pumping at pump-storage plants.

Plant-Use Electricity: The electric energy used in the operation of a plant. This energy total is subtracted from the gross energy production of the plant; for reporting purposes the plant energy production is then reported as a net figure. The energy required for pumping at pumped-storage plants is by definition subtracted, and the energy production for these plants is then reported as a net figure. (See Combined Pumped-Storage Plant, Pumped-Storage Hydroelectric Plant, Pure Pumped-Storage Hydroelectric Plant.)

Power: The rate at which energy is transferred. Electrical energy is usually measured in watts. Also used for a measurement of capacity. (See Capacity, Energy, Watt.)

Power Pool: An association of two or more interconnected electric systems to provide better system reliability and efficiencies.

Price: The amount of money or consideration-in-kind for which a service is bought, sold, or offered for sale.

Prime Mover: The motive force, eg. steam, engine, turbine or water that drives an electric generator.

Profit: The income remaining after all business expenses are paid.

Public Street and Highway Lighting Service: Electricity supplied for the purpose of lighting streets, highways, parks, and other public places; or for traffic or other signal system service, for municipalities, or other divisions or agencies of State or Federal governments.

Pumped-Storage Hydroelectric Plant: A plant that usually generates electric energy during peak-load periods by using water previously pumped into an elevated storage reservoir during off-peak periods when excess generating capacity is available to do so. When additional generating capacity is needed, the water can be released from the reservoir through a conduit to turbine generators located in a power plant at a lower level.

Purchased Power Adjustment: A clause in a rate schedule that provides for adjustments to the bill when energy from another electric system is acquired and its cost varies from a specified unit base amount.

Pure Pumped-Storage Hydroelectric Plant: A plant that produces power only from water that has previously been pumped to an upper reservoir.

Qualifying Facility: A cogeneration facility or small power production facility that is not more than 50 percent owned by electric utilities and meets certain standards as defined under Section 201 of the Public Utilities Regulatory Policies Act of 1978.

Railroads and Railways Service: Electricity supplied to railroads and interurban and street railways, for general railroad use, including the propulsion of cars or locomotives, where such electricity is supplied under separate and distinct rate schedules.

Rate Base: The value of property upon which a utility is permitted to earn a specified rate of return as established by a regulatory authority. The rate base generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost, or original cost. Depending on which method is used, the rate base includes cash working capital, materials and supplies, and deductions for accumulated provisions for depreciation, contributions in aid of construction, customer advances for construction, accumulated deferred income taxes, and accumulated deferred investment tax credits.

Ratemaking Authority: A utility commission's legal authority to fix, modify, approve or disapprove rates as determined by the powers given the commission by a State or Federal legislature. (See Regulation.)

Receipts: Purchases of fuel.

Regulation: A utility commission carries out its regulatory functions through rulemaking and adjudication. Under rulemaking, the utility commission may propose a general rule or regulation change. By law, it must issue a notice of the proposed rule and a request for comments is also made; the Federal Energy Regulatory Commission publishes this in the Federal Register. The final decision must be published. A utility commission may also work on a case-by-case basis from submissions from regulated companies or others. Objections to a proposal may come from the FERC or intervenors, in which case the proposal must be presented to a hearing presided over by an administrative law judge. The judge's decision may be

adopted, modified, or reversed by the utility commissioners in which case those involved can petition for a rehearing, and may appeal a decision through the courts to the U.S. Supreme Court. (See Ratemaking Authority.)

Reserve Margin (Operating): The amount of unused available capability of an electric power system at peak load for a utility system as a percentage of total capability.

Residential Retail Prices of Electricity: Price of electricity supplied to residential customers for lighting, refrigeration, cooling, water heating, and other domestic uses.

Residential Sector: The residential sector includes private household establishments which consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking, and clothes drying. The classification of an individual consumer's account, where the use is both residential and commercial, is based on principal use. Apartment houses are included.

Residual Fuel Oil: The topped crude of refinery operation; includes No. 5 and No. 6 fuel oils as defined in ASTM Specification D396 and Federal Specification VV-F-815C, Navy Special fuel oil as defined in Military Specification MIL-F-859E including Amendment 2 (NATO Symbol F-77), and Bunker C fuel oil. Residual fuel oil is used for the production of electric power, space heating, vessel bunkering, and various industrial purposes. Imports of residual fuel oil include "Imported Crude Oil Burned as Fuel."

Revenue: An increase in the assets of an organization or the decrease in liabilities during an accounting period, primarily from the organization's operating activities. This may include the sale of electricity, and earnings from interest, dividends, lease income and royalties. (See Asset and Liability)

Running and Quick-Start Capability: The net capability of generating units that carry load or have quick-start capability. In general, quick-start capability refers to generating units that can be available for load within a 30-minute period. (See Capability, Load (Electric), Net Summer Capability.)

Sales: The amount of kilowatthours sold in a given period of time; usually grouped by classes of service such as residential, commercial, industrial, and other. Other sales include public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Sales for Resale: A type of wholesale sales covering energy supplied to other electric utilities, cooperatives, municipalities, and Federal and State electric agencies for resale to ultimate consumers. (See Wholesale Sales.)

Scheduled Outage: The shutdown of a generating unit, transmission line, or other facility, for inspection or maintenance, in accordance with an advance schedule. (See Forced Outage.)

Short Ton: A unit of weight equal to 2,000 pounds.

Spinning Reserve: That reserve generating capacity running at a zero load and synchronized to the electric system.

Spot Purchases: A single shipment of fuel or volumes of fuel, purchased for delivery within 1 year. Spot purchases are often made by a user to fulfill a certain portion of energy requirements, to meet unanticipated energy needs, or to take advantage of low fuel prices.

Stability: The property of a system or element by virtue of which its output will ultimately attain a steady state. The amount of power that can be transferred from one machine to another following a disturbance. The stability of a power system is its ability to develop restoring forces equal to or greater than the disturbing forces so as to maintain a state of equilibrium.

Standard Industrial Classification (SIC): A set of codes developed by the Office of Management and Budget, which categorizes business into groups with similar economic activities.

Standby Facility: A facility that supports a utility system and is generally running under no-load. It is available to replace or supplement a facility normally in service. (See Standby Service, Outage.)

Standby Service: Support service that is available as needed to supplement a customer, a utility system, or to another utility if a schedule or an agreement authorizes the transaction. The service is not regularly used. (See Standby Facility, Outage.)

Steam-Electric Plant (Conventional): A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a boiler where fossil fuels are burned.

Stocks (Fuel): A supply of fuel accumulated for future use. This includes coal and fuel oil stocks at the plant site, in coal cars, tanks, or barges at the plant site, or at separate storage sites.

Subbituminous Coal: Subbituminous coal, or black lignite, is dull black and generally contains 20 to 30 percent moisture. The heat content of subbituminous coal ranges from 16 to 24 million Btu per ton as received and averages about 18 million Btu per ton. Subbituminous coal, mined in the western coal fields, is used for generating electricity and space heating.

Substation: Facility equipment that switches, changes, or regulates electric voltage. (See Transformer, Transmission.)

Switching Station: Facility equipment used to tie together two or more electric circuits through switches. The switches are selectively arranged to permit a circuit to be disconnected, or to change the electric connection between the circuits. (See Electric Plant, Substation, Transformer, Transmission.)

System (Electric): Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one central management, or operating supervision.

Total Bill: An itemized statement of fees and charges that consists of the base bill plus State and local taxes and other charges. These charges can include environmental surcharges, franchise taxes, purchased power adjustments, fuel adjustments, and any other taxes passed onto the customer from State and local governments which are collected by the utility.

Transformer: An electrical device for changing the voltage of alternating current.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer. (See Current, Energy, Power, Watt.)

Transmission System (Electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems. (See Transmission.)

Turbine: A machine for generating rotary mechanical power from the energy in a stream of fluid (such as water, steam, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two.

Uniform System of Accounts: Prescribed financial rules and regulations established by the Federal Energy Regulatory Commission for utilities subject to its jurisdiction under the authority granted by the Federal Power Act

Volt: The unit of measurement of electric force or pressure. The electrical force that, if steadily applied to a circuit with a resistance of one ohm, will produce a current of one ampere. (See Ampere, Current, Ohm.)

Voltage Reduction: Any intentional reduction of system voltage by three percent or greater for reasons of maintaining the continuity of service of the bulk electric power supply system.

Watt: The electrical unit of power. The rate of energy transfer equivalent to one ampere flowing under a pressure of one volt at unity power factor.

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Wheeling Service: The movement of electricity from one system to another over transmission facilities of

intervening systems. Wheeling service contracts can be established between two or more systems.

Wholesale Sales: Energy supplied to other electric utilities, cooperatives, municipalities, and Federal and State electric agencies for resale to ultimate consumers.

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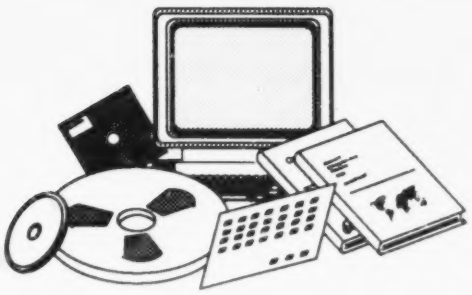

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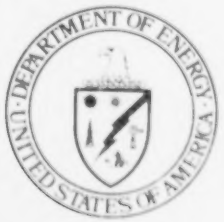
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